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Agricultural Impacts of Oil Shale Development

by

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ABSTRACT

Nearly 2 trillion barrels of oil are contained in the Green River oil shale formation of Colorado, Utah, and Wyoming. However, resource limitations of technology, capital, water and land, as well as great environmental problems of air and water quality, stand in the way of using this oil. Much of the water for oil shale development in Colorado, the area of richest oil shale deposits, would probably have to be diverted from agricultural uses. As much as 20 percent of irrigated farming in Colorado could be lost by such water diversion to oil shale use. However, irrigation losses to farming in Utah and Wyoming would probably be slight from oil shale development in those states. Careful planning could minimize declines in irrigation. In general, impacts on agriculture from land use for oil shale development would not be significant.

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NOTICE AND DISCLAIMER

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Introduction

Oil shale deposits underlie much of the United States. However, the deposits having the greatest commercial interest occur in the Piceance Creek Basin in Eastern Uinta Basin. These Green River formation deposits underlie about 17,000 square miles of land in northwestern Colorado, northeastern Utah, and southwestern Wyoming constituting the largest resource of contained oil in the world. It is estimated that more than two trillion barrels of oil are contained in the Green River oil shale deposits with a yield of at least 10 gallons of shale oil per ton. Higher grade oil shale with at least 25 gallons of oil per ton, represent approximately 750 billion barrels of the resource.

Eighty percent of this higher grade shale oil is located in the Piceance Creek Basin in Colorado, lying between the White and Colorado Rivers in Mesa, Garfield, and Rio Blanco Counties, in Colorado; 15% is in the Uinta Basin of Utah; and 5% is in the Green River Basin in Wyoming. The deposits in Colorado contain the nation's thickest, richest and best defined oil shale resources.

Other minerals of economic interest occurring within the study area include gilsonite, coal, petroleum, natural gas, uranium, phosphate, trona, nahcolite, and dawsonite. Some areas represent opportunities for multiple mineral recovery but development may involve separate facilities, as when oil shale, petroleum, and natural gas occur under the same tract of land. In other areas two or more commodities might be extracted together. An example of the latter would be exploitation of the intermixed oil shale and sodium mineral deposits which occur in the Piceance Creek, Uinta, and Green River Basins.

Mineral rights are vested in four main categories of ownership: federal, state, Indian, and private. Federal lands comprise about 72% of the 11 million

acres containing oil shale and contain nearly 80% of the appraised in-place shale oil. Federal control extends over 79% of the oil shale acreage in Colorado, 77% in Utah, and 62% in Wyoming. Most of the federal acreage is administered by the Bureau of Land Management, with minor amounts under jurisdiction of the Forest Service, Fish and Wildlife Service, Bureau of Reclamation, Bureau of Indian Affairs, and Navy Department. Much of the federal land is currently under lease for oil and gas exploration, livestock grazing, or other commercial uses. Some accommodation between different leases would be required before the affected lands could be opened to commercial development.

After the initial hurdles of starting an oil shale industry are overcome constraints on the growth of the industry may be severe unless sufficient advance effort is made to minimize them. The major constraints may be categorized as environment, technological, legal, policy related, and water supply. Work is progressing on all these fronts; acceleration in some areas may be needed to avoid bottlenecks even if an economic climate favorable to oil shale development materializes. Research is now focused primarily on developing an in-situ oil recovery technology, developing mining methods for the deeper lying rich oil shale beds, and improving environmental protection and technology.

Shale Oil Recovery and Resource Requirements

As now contemplated, an oil shale industry will be the world's largest industry processing low grade minerals. Solids will be mined at a magnitude not heretofore accomplished on an industrial scale. The following example, using 30 gallon per ton shale, illustrates the point. For every 2,000 lbs. of shale mined and then retorted there is obtained 230 lbs. of shale oil product. A 50,000 barrel per day plant will mine about 73,000 tons of shale per day and discard approximately 59,000 tons per day of waste-spent shale. On this basis,

a projected one million barrel per day industry will require the mining of 480 million tons of shale annually which is about 70 percent of the current annual level of U.S. coal production. All of this mining processing must be done in a region in which water is limited and the environment very fragile.

Mining Methods

There are two general types of mining that can be used to produce oil from oil shale. One removes the ore from its natural location for processing in surface retorts. The other relies on applying heat to the in-place ore, a method called in-situ mining.

Surface retorts will normally acquire ore from some form of underground mine or from surface mines using open pits. In room and pillar mining, a portion of the ore body is removed to form large rooms. The rest of the ore is left in place as pillars to support the roof.

Surface mining is economically attractive for large low-grade ore deposits because it permits high recovery of the resource and provides ample room for large and efficient mining equipment. Although large equipment can be used in room and pillar mining, resource recovery from such a mine cannot equal recovery from an equivalent open pit mine. Theoretically, nearly 100% of the resource could be mined and retorted using open pit mining methods.

Open pit mines for oil shale may be very large. One has been described for a proposed 80,000 barrel per day shale plant. In its prime the proposed pit would be 10,000 feet in diameter at the top, 3,000 feet deep, and 4,000 feet in diameter at the bottom. To reach this stage 35 billion cubic feet of overburden and 73 billion cubic feet of broken oil shale will have to be removed. One factor inhibiting surface mining of oil shale is the great thickness of overburden covering the rich shale deposit. In the center of the Piceance Creek Basin the 2,000 ft. thick shale is buried under more than 1,000 feet of overburden.

Pure in-situ technology, which involves no mining, is still under experimental development as an oil shale retorting method and it has only been marginally successful to date. However, in-situ processing should offer many advantages over underground mining and surface retorting. These include: fewer people to operate the process; one-half to two-thirds the amount of water is required; essentially no spent shale is generated for surface disposal; and the capital investment requirement is reduced.

Modified in-situ processing is actually mine-assisted in-situ retorting combining the primary advantages of both underground and in-situ mining processes. A vertical underground retort is prepared by mining enough oil shale from within the mining zone to create a room, blast holes are then drilled upward or outward from the room into the formation. The desired permeability is obtained by detonating explosives in the blast holes. The broken rock fills the void space, creating a chimney of rubble. The mine tunnel is sealed and gas supply and exhaust lines are installed. The top of the shale rubble is then ignited through boreholes drilled from the surface. During retorting, shale oil flows to a sump at the bottom of the underground retort and is then pumped to the surface. The oil shale mined from the cavity, (about 15% to 25% of the mine zone) can be retorted using surface retorts.

Water

Water scarcity in the semiarid oil shale region of Colorado, Utah and Wyoming is considered to be one of the primary constraints on eventual oil shale industry. The many uncertainties regarding the actual supply of water in this region for energy development and other uses plus the lack of information about the water requirements of an oil shale industry make it very difficult to determine how water may eventually influence the size of the industry.

In the past it has been assumed that waste disposal and shale oil upgrading operations would account for roughly 60% of the water requirements for oil shale development. However, recent experience with spent shale from the Paraho retort near Rifle, Colorado, which does not use the finely ground shale, indicates that shale oil disposal could be accomplished without the use of any water. Of course, revegetation would still require water for irrigation.

Also, the mining method may greatly influence the amount of water used for commercial production. A recent estimate of water consumption for a modified in-situ mining technique in the Piceance Basin showed a requirement of about 4,000 acre feet per year for a 57,000 barrel per day plant not using surface retorting of the void shale. This quantity of water is less than half that which would be required for an underground mine using room and pillar methods. The estimated water available from mine dewatering during full operation is expected to almost meet the requirements of this plant. In areas such as the northern portion of the Piceance Creek Basin groundwater may be expected to supply most of the water for shale oil production. Eventually, however, a mature oil shale industry of one to two million barrels per day will require the use of substantial quantities of surface water from rivers and streams in the area.

Land

One of the primary concerns expressed by people in the areas of oil shale developments is the potential land disturbance by mining. It is expected that a one million barrel per day industry would disturb 30 to 35 thousand acres of land in the area at any one time. These figures do not include land requirements for the increased population that would be induced by oil shale development. However, they do include all off-site needs for roads, pipelines, and storage facilities. In-situ or modified in-situ mining methods would be expected to use smaller amounts of land than underground mining, primarily because

of smaller demands for surface disposal of mined or spent shale using in-situ methods.

Costs of Oil Shale Production

Estimates of the cost of oil shale production, and hence the profitability, have been made many times. However, it seems that engineering estimates of cost and profitability are always more favorable than may actually be expected under full scale development. In one report covering 18 separate studies of oil shale production costs certain assumptions underlying the reported cost studies were standardized. Production cost estimates for underground extraction plus surface retorting ranged from \$6.18 and \$10.20 per barrel in 1978 dollar costs. Estimates of costs for conventional and modified in-situ systems ranged from \$10.59 to \$16.73 per barrel in 1978 dollars. In general, the highest cost estimates were made by the construction consultants designing specifications for full-scale facilities. Government estimates were lower than those of the oil shale industry. Recent developments in in-situ technology have reduced the costs for the modified in-situ mining method below those for surface or underground mining methods.

A recent estimate of costs for a 100,000 barrel per day underground mine shows that capital costs could reach \$1.6 billion in 1975 terms for this plant. Some of the more important problems associated with commercialization of oil shale are the rather devastating inflation experienced in the recent past, the sharp increase in capital requirements, and the rather large uncertainties regarding retort and mining technology required for oil shale recovery. Because of such large capital investment requirements and a high operational risk due to the use of unknown or untried technologies, private companies are very reluctant to make such investments at this time. There is also a great deal of uncertainty and risk relative environmental and political issues. Costs associated with providing an environmentally acceptable facility are difficult to

predict in the present stage of development. On the political side, one area of greatest uncertainty is where product prices could be established if subjected to some sort of control while ever-increasing expenses are not.

The Water Resource

Other than the direct and obvious effects of energy development on agriculture through competition for land use, water will provide the greatest degree of interaction and conflict between these activities. Because of such potential conflicts this report devotes part of its analysis to the facts, controversies, and uncertainties surrounding water supplies in the oil shale area. All of the water for oil shale development will necessarily be derived from the Upper Colorado River Basin of Colorado, Utah, and Wyoming.

Several historical legal documents affect the use of water in the Upper Colorado River Basin. Besides the normal in-state laws that apply to all of the Colorado River Basin states, the Colorado River compact of 1922 effectively divided the flows of the Colorado River between the Upper Basin States (Utah, Colorado, Wyoming and New Mexico) and Lower Basin States (Arizona, California and Nevada). The compact established the flow of river available for distribution between the upper and lower basin states at 15 million acre feet per year. Its major provision requires the Upper Basin States to deliver an average of 7.5 million acre feet of water annually to the Lower Basin States.

Allocation of water among the Upper Basin States was accomplished in 1948 by the Upper Colorado River Basin compact. This compact gave Colorado about 52% of remaining upper basin water supplies, Utah 23%, New Mexico 11.25%, and Wyoming 14%. To further complicate the allocations of water in the Colorado River Basin, the Mexican Water Treaty of 1944 provides Mexico an annual quantity of 1.5 million acre feet from any and all sources. The stance of the U.S. Government is that this quantity will be supplied equally by the Upper Basin States and the

Lower Basin States.

One problem created by these various treaties and compacts is the fact that original river flows were over-estimated. More recent data show that the river's total yield is closer to 13.5 million acre feet per year than the original 15 to 18 million acre feet upon which division of resources was made. Thus, the 1922 compact and the Mexican treaty have divided up more water than the river produces. Also, the U.S. Supreme Court in 1908, in what has become known as the Winters Doctrine, held that when Indian reservations were established, sufficient water to supply all Indian lands were also reserved. This decision has made the Indians holding land within the Colorado River Basin an important element in any plans to develop remaining or unused water.

Depending upon the interpretation of the quantity of water contained in the river, Colorado claims on the Colorado River could range from 1.71 to 5.02 million acre feet. Similar variability could be applied to Utah and Wyoming water allocations. Assuming an average gross flow in the river of 14 million acre feet Colorado could have up to 90,000 acre feet of water which is uncommitted and could be devoted to oil shale production. Utah and Wyoming have even larger supplies of water for this use.

Restricting the assumed Colorado River flow to as low as 13.3 million acre feet leave each of the oil shale states with current surpluses of surface water. While there are more plans for this water in Colorado and Utah than can be supported, a very sizable energy industry could be developed without necessarily detracting from any current uses of water. Of course, there would need to be some reordering of priorities if energy development required diverting water from planned development of agricultural or municipal uses.

Environmental Impacts

Assessing the environmental impacts of a potential oil shale industry necessarily involves a great deal of speculation because of the uncertainties

surrounding the choice of technology, the location of development and future size of the industry. Oil shale lands in all three states support large and varied wildlife populations. Most areas embody a combination of natural and cultural conditions that promote good upland habitat, and a few areas contain good fisheries. Virtually all habitats are ecologically fragile.

In-situ and modified in-situ recovery systems are generally regarded as more environmentally benign than underground or surface mining and surface retorting methods. Whether this proves to be the case in all respects is not a certainty.

Land Disturbance

Growth of a mature industry using ex-situ technology would unavoidably involve massive reconstitution of the landscape because of the large tonnage of ore which must be extracted from the ground and the large volume of spent shale which must be disposed after surface retorting operations. Spent shale has little by-product value and it appears that little or none of the wastes will be returned to the mine voids during early development of the industry. The prospects for successfully revegetating hundreds to thousands of acres of spent shale are problematical. Spent shale as it comes from the retort is highly saline, highly alkaline, and essentially devoid of plant available nitrogen and phosphorous.

Restoration of disturbed areas by natural revegetation would be extremely slow. Even on natural soils it takes approximately seventeen years for natural shrub and grass regrowth to take place on small disturbed areas at the lower elevations, and approximately eight years at the higher elevations. Therefore, natural revegetation is probably much too slow to be environmentally acceptable. Thus, there is the requirement for fertilization, leaching, irrigation, and reseeding of these disturbed areas.

At this time, reclamation activities are expected to add 4 to 7 percent to total production costs. It is not expected, however, that the long run productivity of the region will be changed substantially by oil shale development.

Water Quality

Land disturbances produced by mining and spent shale deposits can be expected to change the hydrogeology and water yield of development tracts. Mining of the sub-strata under tens to hundreds of square miles would create many new underground voids. Poorly sealed core holes, well bores, and mine shafts sunk through confining beds would destroy existing boundary conditions. The initial effect would be to deplete the flow of fresh ground waters to springs and creeks in areas such as the Piceance Basin; later depletions would probably involve only saline ground waters.

The already low volume of streamflow originating in the shale watersheds could be permanently diminished by ground water overdrafts, evaporation or drainage waters in abandoned open pits, and by evaporation of storm waters impounded below spent shale dumps. Runoff from the more humid, pinyon-juniper watersheds might be increased if disturbed areas are reseeded with grass rather than woody vegetation and outflow is not depleted by the items described above.

It will be important to avoid undue contributions toward increasing the salinity of the Colorado River. The salinity consideration is reinforced by a 1973 agreement between the United States and Mexico that would limit the salinity of the Colorado River flowing into Mexico to no more than 115 PPM $\pm$ 30 PPM above the average annual salinity of Colorado River Water arriving at Imperial Dam. Salinity is already a serious pollution problem in the Colorado River Basin because of massive irrigation projects in an area with salty soils and because of natural mineral salt sources. There is the possibility that the oil shale industry could add significantly to this problem. However, concern over increasing

salinity should be placed in perspective. Colorado River salinity levels are usually given in terms of concentration at Imperial Dam on the California-Arizona border. It is estimated that the average salinity at this point on the river now measures 865 mg/l. It is further estimated that the salinity concentration at this point would be increased by .1 mg/l per one thousand barrel per day of shale oil production. Because of wide variations in the estimates of water requirements by oil shale complexes, these figures are certainly subject to some wide confidence intervals.

Estimates vary regarding the impact of increased salinity on the Lower Colorado River Basin. The Project Independence Report estimates that externality costs as measured by negative economic impacts on downstream water users will be about $230,000 for each unit increase in salinity at Imperial Dam. Others have estimated similar damages to be as low as $124,000 per mg/l. In any case, it is likely that increased salinity will occur from increased diversions of water from the upper Colorado River for energy development. These impacts will be felt by downstream users in terms of economic costs of some kind.

Air Quality

The size, location, and number of oil shale processing plants in an area will have significant bearing on the ability of the industry to meet current or future air quality standards. Air quality degradation may come from emissions of fugitive dust (particulate matter) and from gaseous emissions including hydrogen sulfide, sulfur dioxide, nitrogen dioxide, carbon monoxide, and various hydrocarbons.

One of the major problems related to air quality control in the oil shale area is the classification of the air sheds given to the region. The area of eastern-northeastern Utah has been given a standard equivalent to the Federal Class II as proposed by EPA, which will allow a considerable energy development in the region.

Colorado, on the other hand, has assigned the area of its oil shale deposits an air quality standard much higher than the Federal Class II standard. In fact, the standards for Colorado are so high that the natural vegetation and dust will violate them at some times. Under these circumstances, it would be nearly impossible to develop a sizable industry in the Colorado portion of the oil shale region without violating the air quality standard. Rio Blanco County, which holds the bulk of the Piceance Creek Basin oil shale deposits, has applied for a change of the air standards in Colorado to Class II. Such a change would be more consistent with the standards applied across the border in Utah and probably would allow a sizable oil shale industry to develop.

Wyoming air quality standards in the oil shale regions are set by the Federal EPA. In this case, they are classified as Class II, similar to those of Utah.

It should be noted, however, that the Occidental Oil Company is moving ahead with development plans in the Piceance Creek Basin of Colorado on the C-b lease tract. This company plans to develop a 57,000 barrel per day capacity plant using a modified in-situ process. At this time, the company is asking for no variances from the Colorado air quality standards in order to proceed with development. Thus, it is expected that some industrial development can occur in the region even under current standards.

Development Scenario

Predictions regarding oil shale development are bound to be very precarious, regardless of attempts to be conservative or general. Enthusiasm and plans for development have hit many peaks and valleys over the past several decades. The potential of the resource was recognized many years ago, but each time that plans for its development began to emerge, a new oil field was discovered. Thus, while there are some current plans to move ahead with oil shale

production using a modified in-situ method of mining, the many failures of the past impose a "wait and see attitude" among most of the industry representatives today.

As background to developing an expected scenario for oil shale production some necessary assumptions were required:

1. There will be a combination of mining methods used in developing the entire resource. Each part of the resource is most amenable to one or two types of mining.

2. Ultimately, those mining methods providing the highest level of resource recovery will become dominant. While some less efficient methods such as underground mining may exist for some time, the ultimate value of the resource is too high for long run dependence on such methods. Thus, surface mining with various combinations of in-situ oil extraction will ultimately prevail because they allow extraction of a greater proportion of the place resource.

3. Limits on the ultimate size of the industry will be determined by a combination of resources (water and capital), environmental conditions, and economics. Water scarcity has long been considered to be a major limitation to a large scale industry. Though large quantities of water will be required to develop the industry, capital limitations and environmental problems (air quality) will also be serious constraints to the industry. It is not possible to predict the exact size of the industry that can develop nor to describe the combination of limiting factors that will prevail. The answers depend upon state and local policies that will develop regarding economic growth and the environment, technologies developed to affect environmental impacts and water requirements, and the price of oil which may encourage or discourage incentives for production.

4. The majority of the oil resource is in the Piceance Creek Basin of Colorado and hence, in the very long run, production must be concentrated there.

However, the oil shale resources in Utah and Wyoming could support sizable industries for many decades. Thus, the problems of water shortage and air quality in Colorado will force the industry to spread first into Utah and ultimately into Wyoming. State policies toward these factors will ultimately influence the size and dispersion of the industry.

This report, using the above assumptions, develops an estimate of mining combinations by state location that can be expected as the industry develops to approximately a 2 million barrel per day level. As development reaches 1 million barrels per day, surface mining and in-situ mining methods will have reached significant levels.

Water Use

Estimated water requirements for an industry size of 250,000 barrels per day average 26,780 acre feet per year. Similar patterns hold for larger oil output levels. These water use coefficients include estimates needed for population increases.

This report has shown that an estimated 451,000 acre feet of water are still potentially available for oil shale development in the three state area. This quantity might be adequate for considerably more than a two million barrel per day industry estimated to use an average 225,780 acre feet of water per year. Unfortunately, the distribution of this water supply is weighted heavily toward Wyoming and Utah where ultimate oil shale development might be less commercially attractive than in Colorado where the major oil shale resources are located. Colorado shows a potential supply of only 90,000 acre feet for all oil shale uses. Hence, the distribution of oil shale production among states might be a major factor in determining the ultimate size of the industry that could develop. However, following this kind of logic alone could place misleading constraints on the development of an oil shale industry. Colorado's share

of the total Upper Colorado River flow is more than twice Utah's share, and more than three times Wyoming's share.

Colorado will most likely experience some serious competition among alternative uses of water as an oil shale industry develops. The degree of this competition depends upon how vigorously the other uses of water are pushed. Coal development, irrigation, and municipal demands for water in Colorado will face stiff competition for oil shale development. About 90 percent of the current water depletions in the upper Colorado River Basin are used by irrigated agriculture at this time. Thus, it is expected that reduction in agricultural water use could provide sufficient water for oil shale development as a last resort. This degree of competition should be unnecessary for sometime however.

In summary, the effect of water limitations on development of an oil shale industry depends upon many currently unanswerable questions. Obviously, the distribution of the industry among the three states in the region will largely affect the problems of water supply that are created. Beyond that the actual limitations of water supply will depend upon the means that are created for allocating or reallocating water supplies within states among competing uses. If the oil shale industry is allowed to compete with other uses on economic terms, including agriculture, it should fare very well and not be severely inhibited from development.

Land Use

Land use requirements for oil shale development will be subject to some of the same variability as described for water. The method of mining, amount of onsite oil upgrading, problems of spent shale disposal and the availability of land are some of the important factors that may influence the amount of land required. It is estimated that approximately 6,550 acres would be occupied or disturbed at any one time by an oil shale industry producing 250,000 barrels per day. Up to 24,000 acres would be required for a one million barrel per day industry.

In an area as vast as the Green River oil shale formation of Colorado, Utah and Wyoming these land requirements are rather small. Most of this land would be in areas of very low population density and economic activity. The major impacts of this land area disturbance will be environmental, though some cattle and sheep grazing will be affected. The environmental effects are difficult to quantify but the land erosion potential and dust production from such an area of disturbed land are not insignificant. Much of this activity could be concentrated in the Piceance Basin where local effect could be substantial.

Agricultural Impacts

Grazing Losses

In the oil shale region livestock ranching, both sheep and cattle, dominate the agricultural uses of land. In general, there is a pattern of using range land for livestock support during the grazing season and then relying on irrigated forage production for the remainder of the year. Thus there is a problem in assessing the impact on range land or on irrigated land by not knowing how much the balance of agriculture may be upset by also affecting the other half of the system. Because of the relatively small portions of either irrigated or non-irrigated agriculture that is likely to be impacted at any one time, however, this problem does not appear to be serious.

The lands likely to be lost to grazing are assumed to be the same as total disturbed lands, excluding urban development needs. It is recognized that some disturbance will occur on croplands, particularly due to roads and pipelines.

Grazing productivity of land within the oil shale region is rather low. In general, this region is semi-arid with short growing seasons. The average grazing yield ranges from a requirement of 9 acres per animal unit month in Colorado to 14 acres per unit in Utah. It is estimated that grazing losses from a 1 million barrel per day industry would equal 1,767 AUM in Colorado, 480 AUM in

Utah, and 120 AUM in Wyoming. Expressing these same data in terms of number of cattle, the loss due to disturbance of grazing lands ranges from 145 for a 250,000 barrel per day industry to 1,054 with a 2 million barrel per day industry. The latter might be compared to the total livestock of 2 to 3 average cattle ranches in this region. In none of the states affected would the grazing losses equal more than 1 percent of total grazing productivity at this time.

These figures may be slightly misleading as a result of the geographic base for calculating their impact. While a county is the smallest governmental or geographic unit for which agricultural data are reported, the actual impacts may be concentrated on an even smaller area. Particularly in the Piceance Basin where oil shale reserves are the deepest, richest, and generally most accessible, there is likely to be a concentration of oil shale activity which could focus losses on a relative few ranchers.

In summary, the grazing losses due to land disturbance from oil shale development are not large by any measure. The annual variation in livestock production or the losses to coyotes could probably exceed the described losses from oil shale activity. Certainly there will be concentrations of effects that will result in greater impacts on some ranches and areas than others.

Irrigated Agriculture

The impacts on irrigated agriculture are somewhat subject to the whims of the industry and development policies in the affected states. A primary source of impact comes through the competition of water provided by the oil shale industry.

Even under a conservative estimate of Upper Colorado River flows neither Utah nor Wyoming should have difficulty meeting the water needs of regional oil shale industry up to 2 million barrels per day. Meeting the water demands of oil shale development in these states should not divert water from agricultural

uses. In fact, the state of Utah plans to build a dam on the White River to supply water to the oil shale industry. This dam would also allow development of about 13,000 acres of irrigated Indian land near the confluence of the White and Green rivers. Thus, oil shale development in Utah may have the effect of increasing agricultural output, at least in the short run.

Colorado appears to have adequate water for oil shale development up to an industry level of about 500,000 barrels per day, if an optimistic view of water supplies is taken. If a lower level of water flow is assumed for the Colorado River, Colorado's excess quickly diminishes to zero. Under this circumstance there is a possibility that the oil shale industry would begin to compete with agriculture for water at the very infant stages of development. Assuming these water demand and supply data are accurate and that all such water must be provided by surface flows in Colorado, it is possible to estimate how seriously agriculture would be impacted.

There are currently about 413,000 acres of irrigated land in two river basins of Colorado containing oil shale, consuming about 770,000 acre feet of water per year. Assuming the worst possible case to prevail in which all the water for a 2 million barrel per day industry would come from agriculture, or 151,000 acre feet in Colorado, it is estimated that irrigated acreage could be reduced by 81,000 acres. This would mean a potential reduction of 20 percent of the irrigated agriculture of these two river basins in order to support oil shale development.

There are a number of mitigating factors to be considered that would certainly temper the potential detrimental impact on agriculture. There are technological options in mining, retorting, and upgrading oil shale that could adjust the water use in the industry over a wide range. Thus, the water coefficients used in this report and elsewhere are generally considered to be a "worst case"

condition. If water is available and cheap the oil shale industry will probably use it in significant quantities. If water supplies become restrictive the industry could probably develop using much less water than previously anticipated.

In summary, it should be possible to develop an oil shale industry exceeding 2 million barrels per day and have only minimal impacts on agriculture through competition for water. Since much of the water used by agriculture in this region is rather inefficiently applied and utilized, there may be opportunities for "saving" enough water in agriculture to offset the needs of an oil shale industry. Of course, the costs to agriculture for achieving this water saving could be very high. Also, there would have to be changes in the legal and institutional factors surrounding water rights in order to compensate agriculture for such water saving measures and to divert the saved water to energy development.

Urban Growth

Aside from the use of agricultural water for industrial and urban growth there is also other competition for land imposed on irrigated agriculture by urban growth and the recreation industry. The level, accessible irrigated lands in the valleys of the oil shale region are the most amenable to urban development. Water is generally available. Roads, streets and other necessary utilities are easily constructed. The question is how much of the currently irrigated land is likely to be used for development.

In answering this question it was assumed that all potential urban growth due to oil shale development will occur on irrigated land. Under this assumption approximately 28,000 acres of cropland could be absorbed by urban development resulting from a 2 million barrel per day industry. While this in itself may overstate the use of irrigated land for dwellings, there will undoubtedly be some growth in ancillary industries and business to require land which this analysis does not directly measure. These two factors should be somewhat offsetting.

There are changes in agriculture already occurring in the oil shale region which may have a bearing on the measure of impacts resulting from oil shale development. Commercial agriculture is already non-existent or diminishing rapidly in portions of the area due to recreational pressures. These developments have priced land out of reach for most agricultural uses in recent years with the result that agriculture is diminishing in importance. Thus, the imposition of an oil shale industry can only accelerate a process that is already underway in many cases. In fact, the agricultural impacts of an oil shale industry are likely to be smaller than those already felt from recreational developments.

Socio-Economic Impacts

Manpower requirements per 1000 barrels per day output from underground mining activity would be approximately 21 employees for the mining activity with approximately 30 secondary employees through induced employment. Thus, total employment at full production would be approximately 51 man equivalents per thousand barrels per day output. A modified in-situ process would have slightly higher employment needs.

It is assumed that populations associated with construction employment will be relatively transitory. They will most likely congregate in rather densely populated mobile home tracts. It is assumed that the lag time for significant population increase will be sufficient to allow urban planners to discipline the patterns of urban growth. Due to recognized importance of preserving irrigated land and water in the oil shale region the more permanent urban growth will be in the form of traditional city lots. There will be significant investments required in public service facilities to service the needs of population growth. Good planning will be necessary at all levels of government to avoid imposing large development costs on local communities.

Conclusions

The Green River oil shale formation of the western Rockies contains the largest known oil resource in the entire world. Nearly 2 trillion barrels of oil are known to be in place in this region of Colorado, Utah, and Wyoming. Of this total, as much as 600 billion barrels could be recovered with current technology.

Unfortunately, there are many obstacles in the way of recovering and using this oil resource. Resource limitations of water, land, and capital, as well as monumental environmental problems of air and water quality, stand in the way of using this oil.

This study has shown that there are many uncertainties surrounding both the supply of water for energy development and the anticipated demand for such development. The compounding of these factors leaves in doubt the real potential of water availability for oil shale development in this region. However, the results of this study indicate that there is water available in the region of the oil shale for development. In many cases, the water will have to be diverted from other anticipated uses or current uses in order to be made available for energy. This possibility of competing uses creates one of the potential impacts for the region that may follow oil shale development. Most such water, particularly in Colorado, will probably come from agricultural uses in the long run.

The agricultural impacts of oil shale development are not entirely predictable. It is not expected that impacts through competition for land use will be very significant. The magnitude of disturbed land from oil shale development and irrigated land used for urban growth are both relatively minor in comparison to the agricultural base of the region. The competition for water could potentially have larger impacts on agriculture, though it is difficult to be precise in this matter. Much depends upon the ultimate size of the industry, its

location and/or distribution in the state, the actual availability or supply of water (particularly in Colorado), and the technologies or methods used to extract oil from shale. As much as 20 percent of current irrigated agriculture could be lost in this manner in Colorado. Such losses should be negligible in Utah and Wyoming. Planning by state and local governments and industry representatives could significantly mitigate potential impacts on agriculture without unduely discouraging development of the oil shale industry.

Introduction and Area Description

Purpose

The major objective of this report is to provide an assessment of the potential agricultural impacts of a large scale oil shale industry. While a great deal has been written about the potential and problems of obtaining oil from oil shale, there has been no previous concerted effort to measure potential impacts on agriculture. In the process of analyzing this question, this report also addresses the major limitations and uncertainties that may be faced in the development of a commerical oil shale industry. The report describes the water and environmental problems in some detail because they represent some of the major obstacles to be overcome in the dry, fragile environment of the West containing the major oil shale resources of the United States.

Location of Study Area

This study will focus on the oil shale deposits of the Green River Formation which underlie about 17,000 square miles of land in northwestern Colorado, northeastern Utah, and southwestern Wyoming (Fig. 1). The deposits having greatest commercial interest occur in the Piceance Creek Basin and eastern Uinta Basin. The Piceance Creek Basin lies between the White and Colorado Rivers in Mesa, Garfield, and Rio Blanco Counties, Colorado. The richest deposits in the Uinta Basin lie east of the Green River and generally south of the White River in Uinta County, Utah. Other areas of potential economic interest include the Uinta Basin area west of the Green River in Uinta and Duchesne Counties, Utah; the Green River Basin in Sweetwater, Lincoln, and Uinta Counties, Wyoming; the Washakie Basin in Sweetwater County, Wyoming; and the Sand Wash Basin in Moffat County, Colorado. All of the areas possessing deposits of significant commercial interest are situated in the Upper Colorado River Basin.

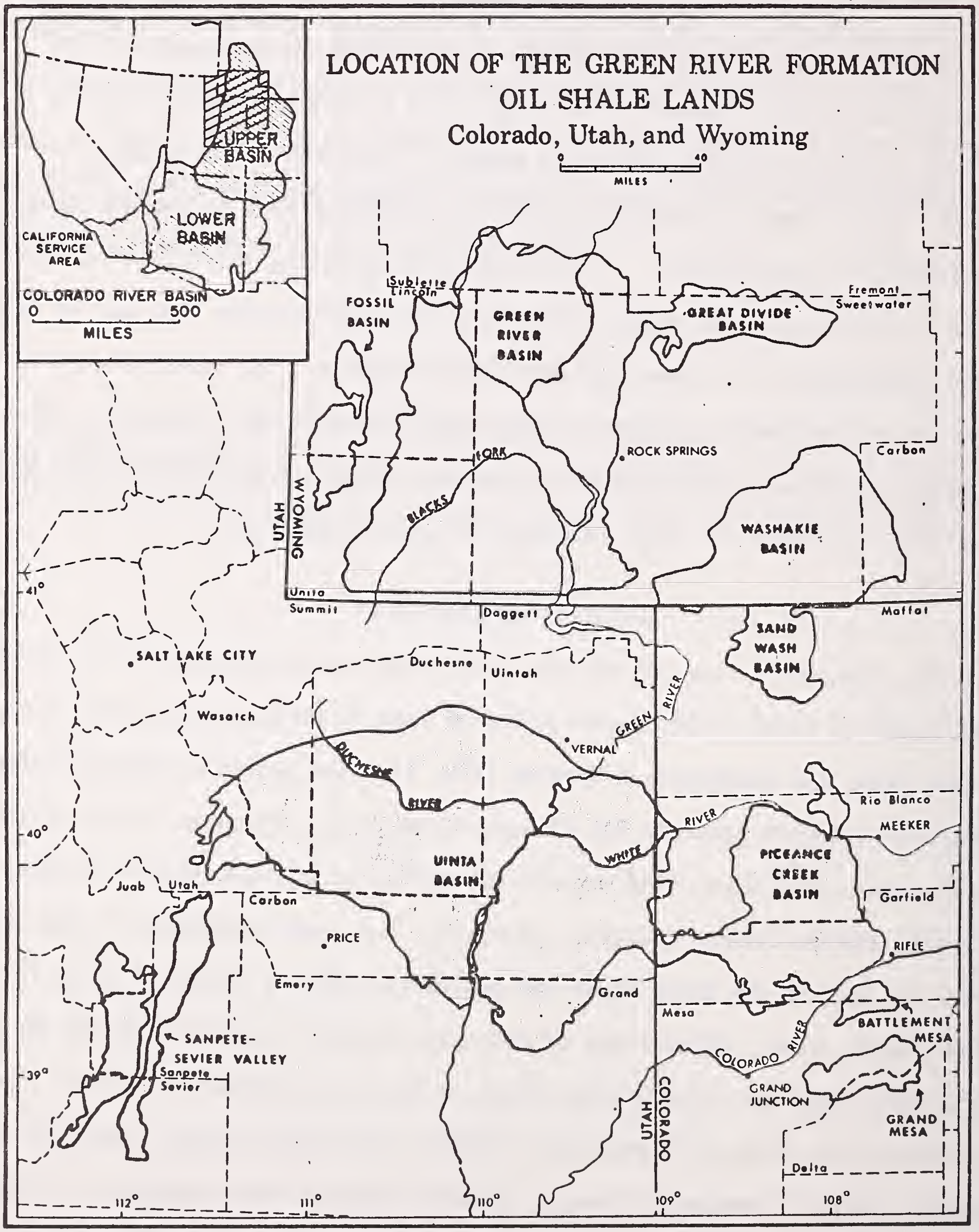

LOCATION OF THE GREEN RIVER FORMATION
OIL SHALE LANDS
Colorado, Utah, and Wyoming
0 40
MILES
UPPER BASIN
LOWER BASIN
CALIFORNIA SERVICE AREA
COLORADO RIVER BASIN
0 500
MILES
FOSSIL BASIN
GREEN RIVER BASIN
GREAT DIVIDE BASIN
WASHAKIE BASIN
SAND WASH BASIN
UINTA BASIN
PICEANCE CREEK BASIN
SANPETE-SEVIER VALLEY
BATTLEMENT MESA
GRAND MESA
Sublette
Lincoln
Fremont
Sweetwater
Carbon
ROCK SPRINGS
UTAH
WYOMING
Uinta
Summit
Daggett
Moffat
SALT LAKE CITY
Duchesne
Uintah
Wasatch
VERNAL
GREEN RIVER
DUCHESNE RIVER
WHITE RIVER
Rio Blanco
MEEKER
Garfield
RIFLE
Juab
Utah
Carbon
PRICE
Emery
Grand
Mesa
COLORADO RIVER
GRAND JUNCTION
Sanpete
Sevier
COLORADO
Delta
BLACKS FORK
41°
40°
39°
112°
111°
110°
109°
108°

Figure 1

Mineral Resources

Actually, oil shale deposits underlie much of the United States. But it is the Green River Formation deposits in Colorado, Utah and Wyoming that constitute the largest resource of contained oil shale in the world (Sladek, 1974, p. 9). The other United States deposits, in the eastern and central states, underlie a much larger area but are lean in oil content and occur in relatively thin beds. In fact, the estimated shale oil resource in the eastern and central United States is less than one-half the Green River deposits, as shown in table 1.

In 1974, Donnell estimated that more than 2 trillion barrels of oil equivalents were contained in Green River shale oil deposits with a yield of at least 10 gallons of shale oil per ton, see Figure 2. Higher grade shales, those with at least 25 gallons of shale oil per ton, represent approximately 750 billion barrels of the resource. Eighty percent of this higher grade resource, or about 650 billion barrels is located in the Piceance Creek Basin in Colorado; 15 percent or 133 billion barrels is in the Uinta Basin of Utah; and 5 percent or 38 billion barrels is in the Green River Basin in Wyoming (Morse, p. 4, 1976). Table 2 summarizes the oil shale resources for the Green River Formation. As the grade of oil shale increases, Colorado's percentage of both in-place and recoverable resources also increases. Colorado has the nation's thickest, richest and best defined oil shale resource (Morse, p. 4, 1976).

It is interesting to note that the estimates of the total shale oil resources in place are highly variable. Some estimates of the shale oil resource in the United States have been estimated as high as 27 trillion barrels of oil (Rattien and Eaton, 1976). This would seem to be a very large resource when compared with similar estimates for domestic coal resources in place: 15 trillion barrels equivalent. Similarly U.S. crude petroleum resource in place are estimated to range between 0.2 and 0.35 trillion barrels of oil.

Table 1. Shale Oil Resources of the United States * (billions of barrels).

Shale Oil Yield Range (gallons/ton)	5- 10	10- 25	25+
Green River Formation (Colorado, Utah, Wyoming)	4,000	2,800	1,200
Central and Eastern U.S.	2,000	1,000	n/a**
Alaskan deposits	large	200	250
Other deposits	134,000	22,250	500
TOTAL (rounded)	140,000	26,000	2,000

*Includes oil shale in known resources, in extensions of known resources, and in undiscovered but anticipated resources.

**Estimate not available.

Source: Sladek, 1974, p. 9.

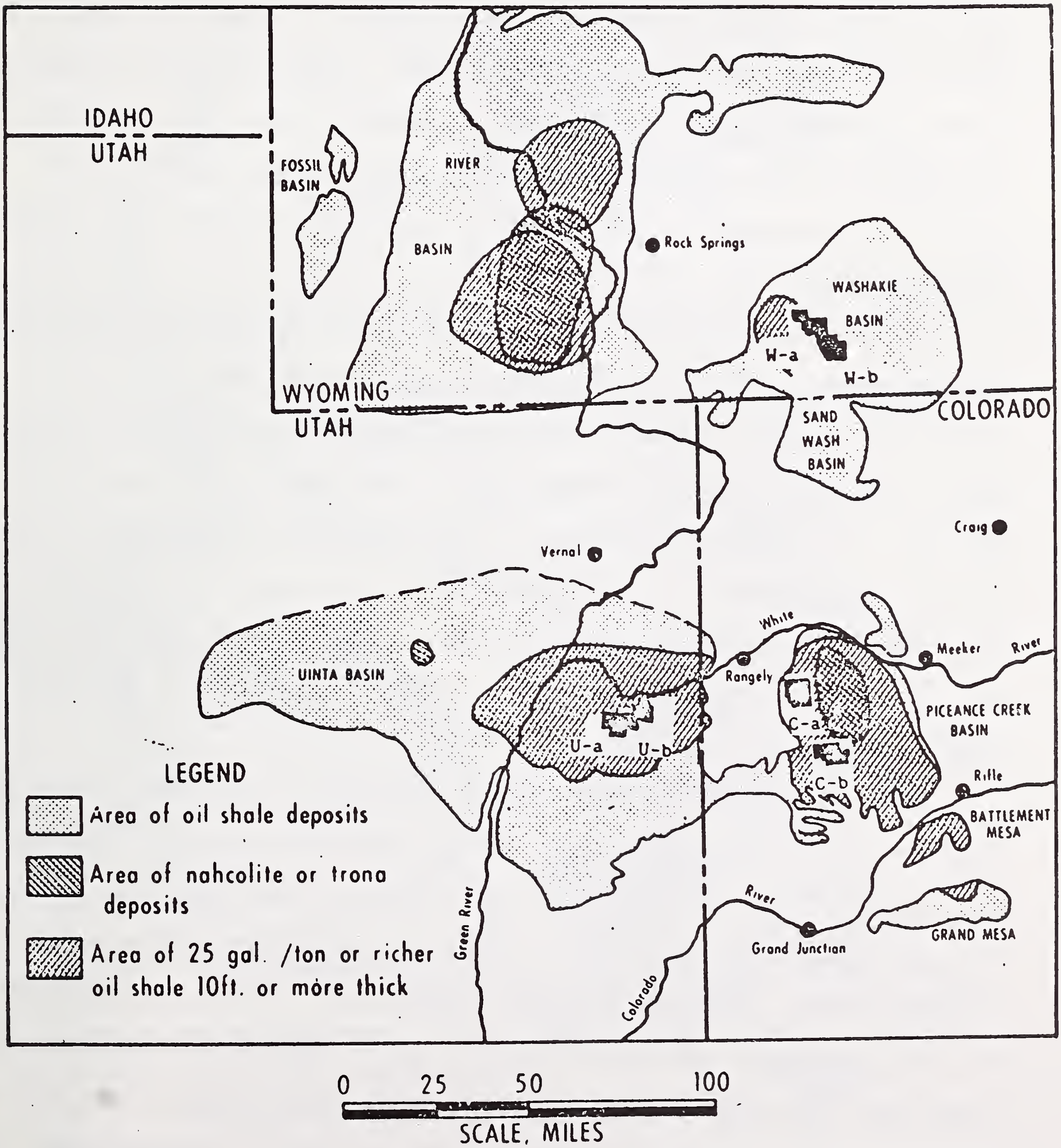
Table 2. Oil Shale Resources (billions of barrels) in Beds at Least 10 Feet Thick.

		≥15 gal/ton shale
Colorado		1,200
Utah		321
Wyoming		321
	Total	1,842
		≥ 25 gal/ton shale
Colorado		607
Utah		64
Wyoming		60
	Total	731
		≥30 gal/ton shale
Colorado		355
Utah		50
Wyoming		13
	Total	418

Source: Ash, 1974, as taken from Morse, 1976.

Figure 2.

OIL SHALE AREAS
COLORADO, UTAH, AND WYOMING



Other minerals of economic interest occurring within the study area include gilsonite, bituminous sandstones, coal, petroleum, natural gas, uranium, phosphate, trona, nacholite, dawsonite, shortite, and halite (U.S.D.I., 1973, a). Many areas present opportunities for multiple mineral recovery. Development in some areas may involve separate facilities, as when oil shale, petroleum, and natural gas occur under the same tract of land. In other areas two or more commodities might be extracted together. An example of the latter would be exploitation of the intermixed oil shale and sodium mineral deposits which occur in the depocenters of the Piceance Creek, Uinta, and Green River Basins (Rothberg, 1974).

Recovery potential of the inplace shale oil is a function of various interrelated factors, including shale grade, thickness of the deposit, depth of overburden, presence or absence of suitable roofstone for underground mining, water content of the mining horizon, rate of water seepage from enclosing formations, stratigraphic relationships to other economic minerals, availability of solid waste disposal sites, availability of process water, air pollution meteorology of the development tract, climatic constraints on the success probability of land reclamation, competition with wildlife habitat or other nonmineral values, and land ownership.

Locations of special interest within the Piceance Creek Basin include the southern margin of the Roan Plateau, the Cathedral Bluffs-Calamity Ridge area, and the north-central portion of the basin (Fig. 3). Room-and-pillar mining of the rich Mahogany beds has already been demonstrated in the southern margin of the Roan Plateau (Kilburn, Atwood, and Broman, 1974). Mining costs are lower in this area because adits can be driven into the target shales which crop out along the cliffs bordering the Colorado River and its tributary valley reentrants, and because water seepage into the mine voids would not be a major problem. The

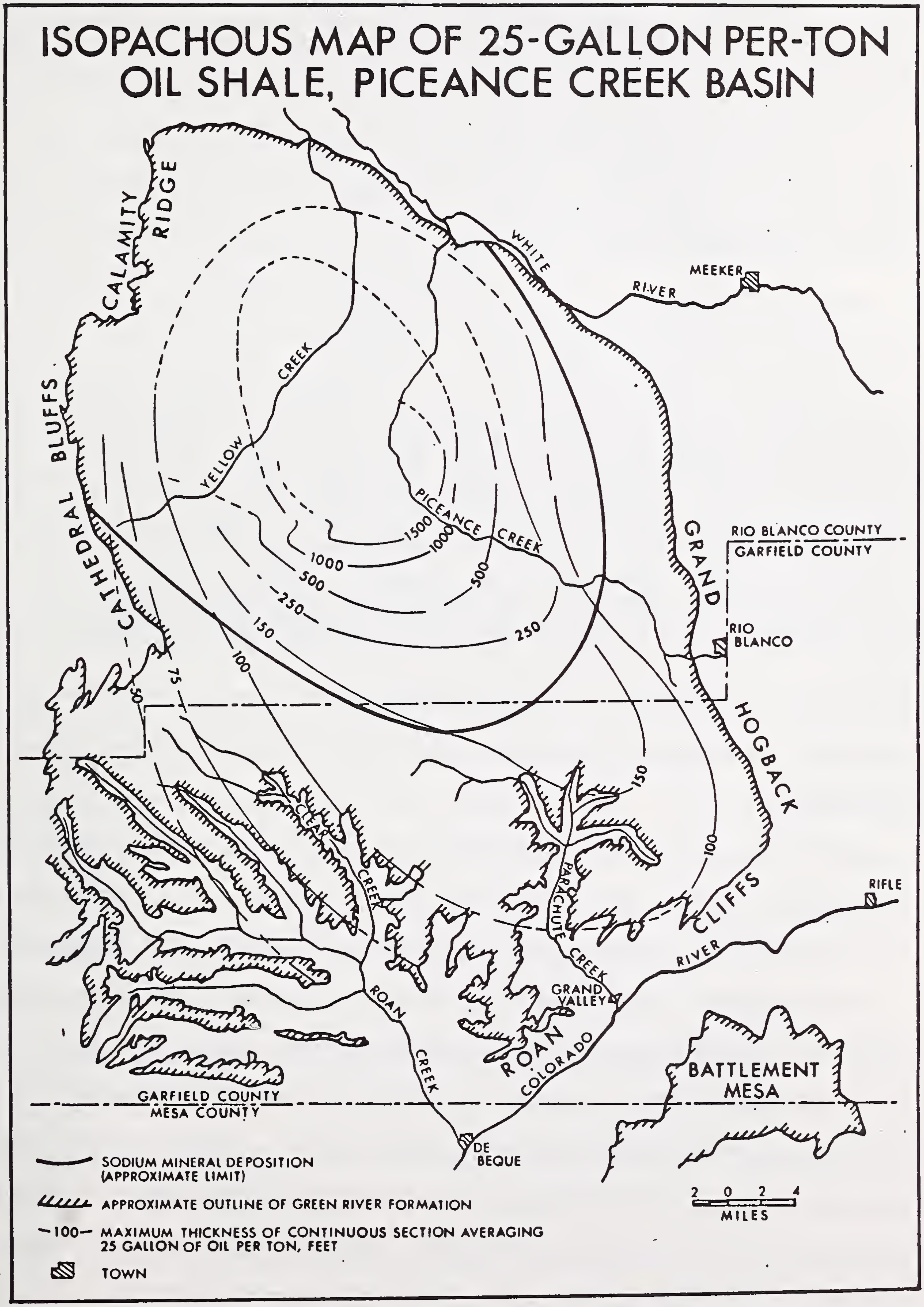

ISOPACHOUS MAP OF 25-GALLON PER-TON OIL SHALE, PICEANCE CREEK BASIN
CALAMITY RIDGE
CATHEDRAL BLUFFS
WHITE RIVER
MEEKER
YELLOW CREEK
PICEANCE CREEK
1500
1000
500
250
150
100
75
50
GRAND HOGBACK
RIO BLANCO COUNTY
GARFIELD COUNTY
RIO BLANCO
CLEAR CREEK
PARACHUTE CREEK
CLIFFS
RIFLE
RIVER
GRAND VALLEY
ROAN CREEK
ROAN
COLORADO
BATTLEMENT MESA
GARFIELD COUNTY
MESA COUNTY
DE BEQUE
SODIUM MINERAL DEPOSITION (APPROXIMATE LIMIT)
APPROXIMATE OUTLINE OF GREEN RIVER FORMATION
—100— MAXIMUM THICKNESS OF CONTINUOUS SECTION AVERAGING 25 GALLON OF OIL PER TON, FEET
TOWN
2 0 2 4
MILES

Figure 3

favorable hydrology also makes the area an attractive site for in-situ or modified in-situ processing of the shale deposits (Chew, 1974). About 26 square miles of land in the Cathedral Bluffs-Calamity Ridge area are underlain by rich oil shales with less than 200 feet of overburden, and an additional 49 square miles are underlain by shales with less than 400 feet of overburden (Donnell and Austin, 1971). The area lies on the northwest margin of the basin, is amenable to open pit or underground mining, and contains spent shale disposal sites in the dry stream canyons tributary to Douglas Creek. Deposits in the northcentral portion of the basin are of unique interest because of their extraordinary thickness of up to 2,000 feet and because of their associated saline mineral suits of halite, nahcolite, and dawsonite (Beard, Tait, and Smith, 1974; Dyni, 1974). Various companies have investigated the potential of processing oil shale, nahcolite, and dawsonite in one integrated operation. Unfortunately, mining costs would be high because of the thick overburden and the low recovery efficiency of underground mining. Progress in the development of in-situ or modified in-situ mining methods may raise the recovery rate of some area minerals.

The Piceance Creek and Uinta Basins are both structurally asymmetrical, having their steepest dips on the north limb and more gentle dips on the south. In the Uinta Basin, however, the structural axis is displaced considerably north of the topographic axis, which means that oil shale deposits on the northern margin are buried to depths of at least 6,500 feet (Cameron and Jones, 1964). The best-known and most commercially attractive deposits occur east of the Green River and generally south of the White River. Federal Lease Tracts U-a and U-b are located immediately south of the White River where the overburden thickness varies from 550 to 1,225 feet. Cashion (1967) has identified three potential development sites south of the lease tracts having less than 100 feet

of overburden, and Cameron and Jones (1964) have identified about 125 square miles that might be amenable to strip mining.

The thickest and richest deposits in the Green River Basin occur mainly in the southeastern part of the basin (Culbertson, 1969). Westward, southward, and northward from this area, the oil shales begin to wedge out and are replaced by tongues of barren or low-grade detritus. The more deeply buried deposits composed of alternating lean and rich beds may be uniquely amenable to in-situ retorting (Smith and Trudell, 1968).

Oil shale deposits in the Washakie Basin have an aggregate thickness of more than 1,000 feet, but the sparse data from outcrop samples and drilling indicate that probably less than 15 percent of the shales yield 15 gallons or more per ton (Roehler, 1969). Principal interest to date is limited to the shales which form the upper scarp slope of Kinney Rim along the western margin of the basin (U.S.D.I., 1973;b). Deposits in the Sand Wash Basin have been little investigated and are thought to be relatively thin and lean (McKay, 1971).

Mineral Ownership

Mineral rights are vested in four main categories of ownership: federal, state, Indian, and private (Widman and Brightwell, 1969). Federal lands comprise about 72 percent of the 11 million acres and contain nearly 80 percent of the appraised shale oil (U.S.D.I., 1973, a, v.I.). Federal control extends over 79 percent of the oil shale acreage in Colorado, 77 percent in Utah, and 62 percent in Wyoming. Most of the federal acreage is administered by the Bureau of Land Management, with minor amounts under jurisdiction of the Forest Service, Fish and Wildlife Service, Bureau of Reclamation, Bureau of Indian Affairs, and Navy Department. Much of the federal land is currently under lease for oil and gas exploration, livestock grazing, or other uses. Some accommodation between different leases would be required before the affected lands

could be opened to commercial development. Some accommodation would also be necessary for those lands in which the surface rights are in private ownership. Additionally, the legal status of old placer claims would have to be clarified. In 1968, for example, title to about 85 percent of the total federal acreage was clouded by unpatented mining claims (U.S.D.I., 1973, a, v.I). A map showing mineral ownership in the Piceance Creek Basin is included is Figure 4.

The Colorado Game, Fish and Parks Commission administers about 31,000 acres in northern Piceance Creek Basin as a wildlife experiment station and management area. The Utah Division of State Lands holds mineral rights to about 233,500 acres of school grant-land in the Uinta Basin. The mineral rights are leased to private companies, but commercial development of the lands would be handicapped because they occur as isolated tracts of only 640 acres each. A recent U.S. District Court ruling awarded the State of Utah an additional 157,000 acres of oil shale land in the east-central portion of the Uinta Basin, including the two tracts leased by the Department of the Interior in 1974. The disputed acreage is part of Utah's in lieu entitlement of school grant lands which could not be conveyed when Utah gained statehood in 1896 because some grant lands were already held as military or Indian reservations. The Wyoming Division of Public Lands administers about 67,000 acres located in Sweetwater County. The state lands have been withdrawn from oil shale leasing since 1963.

The Uinta and Ouray Indian reservation encompasses over 800,000 acres of land in Duschesne, Grand, Uinta, and Wasatch Counties, Utah. Much of this land is underlain with oil shale. In 1971, the Department of the Interior revoked an earlier oil shale withdrawal order pertaining to lands within the reservation, leaving undisputed ownership of mineral rights to the tribe.

Private ownership of lands within the shale basins originated under homestead patents, under mineral patents issued prior to passage of the Mineral

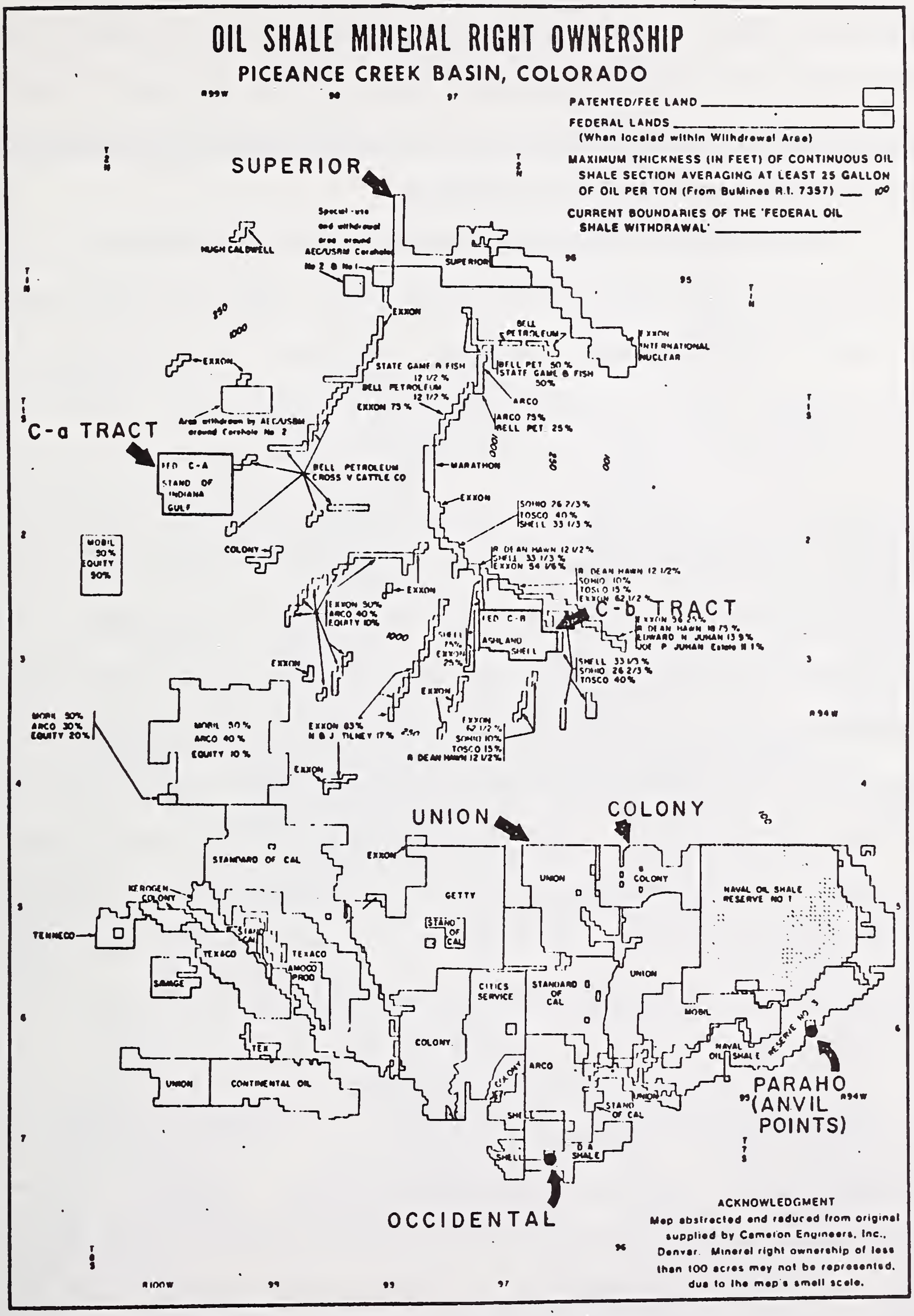


Figure 4. Oil Shale Mineral Right Ownership, Piceance Creek Basin

Source: Western Oil Reporter, January 1974, p. 11
(taken from Morse, 1976)

Leasing Act of 1920, or under federal place grants to the railroads. Most of the fee land in the Piceance Creek and Uinta Basins is now owned or held under option by energy companies. Most of the privately owned land in Wyoming is held by the Union Pacific Railroad Company.

In 1973 the Federal government attempted to stimulate industrial development of the oil shale resources by leasing certain federally owned lands to private industry for development. Two lease tracts were identified in each of the affected states, Figure 2. The Colorado sites, Federal Lease tracts C-a and C-b, were located in the Piceance Creek Basin. They were specifically selected to encourage experimentation of open pit and underground mining techniques. Utah tracts U-a and U-b were adjacent to one another in the Central Uinta Basin near the White River. They were intended for development by underground mining-surface retorting methods. Two tracts were set aside in the Green River Basin of Wyoming, W-a and W-b, for intended in-situ development. Bids for the Wyoming tracts were never forthcoming, however. Bids on the Colorado and Utah tracts were accepted by the Federal Government but after extensive study in both areas decisions were made not to develop because of environmental and economic problems. Development plans for the Colorado tracts have recently been modified to consider in-situ and modified in-situ mining techniques.

Altitude and Topography

The Green River, Washakie, and Sand Wash Basins form part of the Wyoming Basin physiographic province, as defined by Thornbury (1965). All three areas are relatively shallow structural and topographic basins bordered by outward-facing escarpments which stand 400 to 1,000 feet above the surrounding terrain (Bradley, 1964); Roehler, 1969). The basin floors typically lie between 6,200 and 7,000 feet, and are level to gently rolling except where broken by isolated mesas, buttes, or badlands (Fig. 5). Relief in the more broken tracts varies

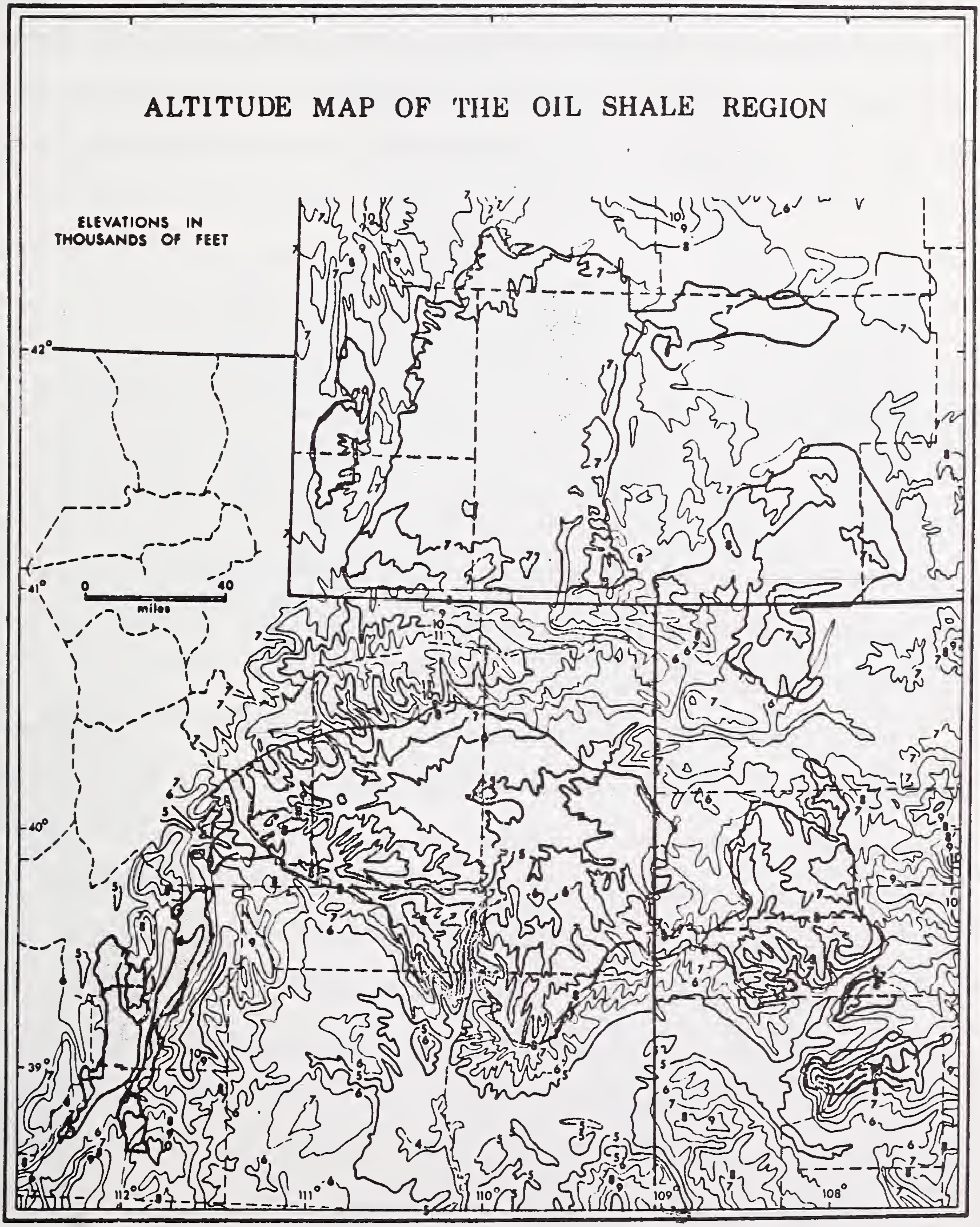

ALTITUDE MAP OF THE OIL SHALE REGION
ELEVATIONS IN THOUSANDS OF FEET
0
40
miles
42°
41°
40°
39°
112°
111°
110°
109°
108°

Figure 5

from 100 to 1,500 feet. All three basins are drained by the Green River and its tributaries.

The oil-shale areas lying south of the Uinta Mountains belong to the Colorado Plateau physiographic province. Stream dissection in the Piceance Creek Basin has created a landscape of elongated ridges, low to moderately-high rounded hills, and abrupt cliffs interspersed with open valleys and upland parks (Donnell, 1961; Schumm and Olson, 1974). The northern two-thirds of the basin lies at an altitude of 6,000 to about 8,500 feet and drains northward to the White River. Local relief between valley floors and adjoining ridge crests is as much as 500 feet. The Cathedral Bluffs is a prominent cuesta escarpment forming the western margin of the Piceance Creek basin that has relief of up to 2,000 feet. The southern one-third of the basin constitutes a high plateau draining southward to the mainstem of the Colorado River. It is dissected by deep canyons and terminates in the Roan Cliffs, which form an irregular line of precipitous escarpments that rise from about 4,900 feet altitude near DeBeque to about 9,400 feet in the vicinity of Rifle.

Uinta Basin is a complex assemblage of nearly level plains, steep-walled canyons, badlands, narrow elongated ridges, and benchlike or mesalike forms (Marsell, 1964). Most of the flatter land occurs at 4,000 to over 6,000 feet altitude in the northeastern part of the basin. Local relief averages 30 to 50 feet, but in some places is as much as 1,000 feet. Stream dissection increases notably south of the Strawberry, Duchesne, and White Rivers. This section of the basin, known as the Tavaputs Plateau, rises southward with the dip of the underlying rocks and reaches altitudes of over 9,000 feet before terminating in the Roan and Book Cliffs. The Green River traverses the basin from north to south and receives runoff from the entire area.

The more dissected portions of the shale basins offer some advantages for mineral development, as the oil shale deposits are sometimes close to the surface or are exposed along canyon walls. Spent shale disposal would also be expedited by using the dry stream canyons as fill sites. On the other hand, areas of dissected terrain tend to be the most scenic lands, and valley locations are especially vulnerable to the accumulation of air pollutants.

Climate

The oil shale region is characterized by abundant sunshine, warm summer temperatures, moderately low winter temperatures, low annual precipitation, low relative humidity, and high evapotranspiration potential (U.S. Weather Bureau, 1964). January air temperatures average slightly above or below 20° F. at elevations below 6,000 feet; while July temperatures at the same elevations average in the 60's to low 70's. Daytime maxima during midsummer commonly exceed 85° F., and winter minima often fall well below 0° F. Temperatures adjacent to the ground surface may differ widely over short distances because of variations in slope, aspect, elevation, vegetal cover, and surface wind patterns. The frost-free season ranges from about 50 days at the higher elevations to 125 days at lower elevations.

Altitude and topographic exposure determine the amount and spatial patterns of precipitation (Iorns, et al., 1965). Average annual values range from less than 8 inches over large areas in Wyoming and Utah to about 30 inches in a few isolated highland locations (Fig. 6). Low values prevail throughout the Wyoming shale lands. The Utah lands exhibit greater diversity because of marked differences in altitude and exposure; annual amounts range from 8 inches or less in the northcentral Uinta Basin to 16 inches or more at higher altitudes. Precipitation in the Piceance Creek Basin varies from about 10 inches at the lowest elevations to over 20 inches at elevations above 8,000 feet (Wymore, 1974).

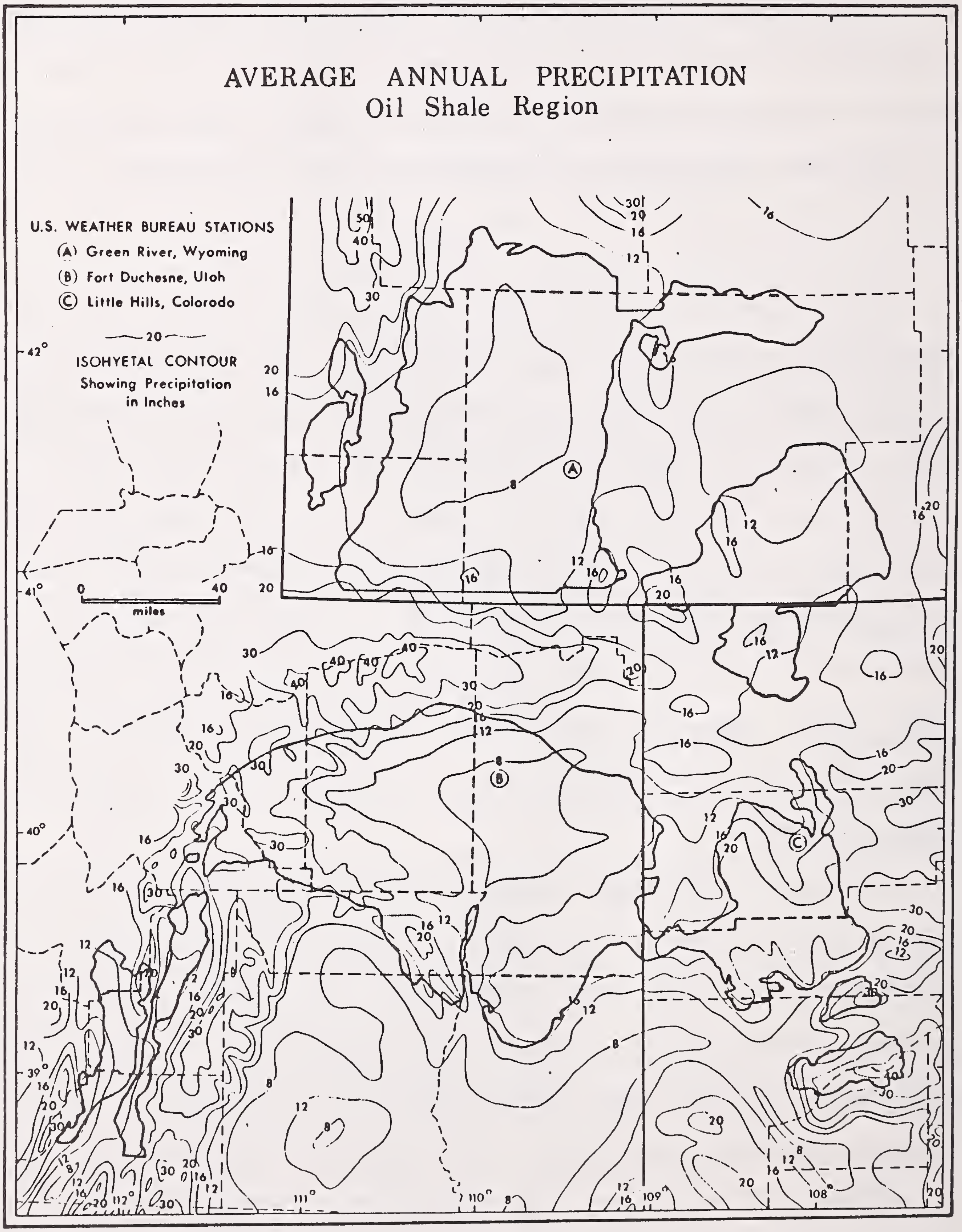

AVERAGE ANNUAL PRECIPITATION
Oil Shale Region
U.S. WEATHER BUREAU STATIONS
(A) Green River, Wyoming
(B) Fort Duchesne, Utah
(C) Little Hills, Colorado
20
ISOHYETAL CONTOUR
Showing Precipitation
in Inches
0
40
miles
42°
41°
40°
39°
112°
111°
110°
109°
108°

Figure 6

Seasonal distribution of precipitation is fairly uniform, with slightly less than half occurring from October to April, largely in the form of snow. Snowmelt and spring rains generate most of the annual water yield. Summer precipitation takes the form of sporadic showers and occasional cloudbursts. Although rainfall associated with shower activity seldom exceeds the retention capacity of the vegetation and soil surface, the high-intensity convectional storms produce ephemeral floods with resulting bridge damage, sheet erosion, gully erosion, and bottomland siltation.

Annual sunshine, high summer temperatures, and low relative humidity combine to produce high rates of potential evapotranspiration. The net effect is to intensify soil moisture deficiency, especially at the lower elevations where rainfall input is least. Wymore (1974) estimates that potential evapotranspiration on horizontal surfaces in the Piceance Creek Basin ranges from 46 inches at elevations of 6,000 feet to about 37 inches at elevations of 8,000 feet. Using the modified Thornthwaite moisture index (Thornthwaite and Mather, 1957), which considers the interaction of precipitation, evapotranspiration, and soil field capacity, most of the shale region would be classed as semiarid or dry subhumid.

Ground Cover and Land Use

Vegetal cover consists mainly of native species (Iorns, et al., 1965). Domestic livestock grazing and timber-cutting have partially removed or otherwise deteriorated the original cover in most areas, but the overall effect has been minimized as a consequence of range-improvement programs conducted by the Bureau of Land Management and private ranchers. Only a small percentage of the total acreage is presently cultivated or has ever been cultivated.

Ward and coworkers (1974) recognize 18 different plant communities in their

analysis of the Piceance Creek Basin. However, for general purposes it suffices to identify three vegetation zones based on dominant vegetation type and altitudinal zonation (Fig. 7).

The mixed desert shrub zone occurs over most of the Wyoming lands, and is found in Utah and Colorado at elevations generally below 6,500 feet. Density of ground cover generally ranges between 5 and 25 percent, except along bottomlands of perennial streams where phreatophytes and riparian vegetation form an essentially continuous cover. The zone comprises a complex mixture of woody and herbaceous species, each adapted to particular site conditions of soil moisture, salinity, and alkalinity. Major shrubs include sagebrush, rabbitbrush, blackbrush, greasewood, shadscale, and salt-brush. Understory grasses include galleta, blue gamma, western wheatgrass, bluebunch wheatgrass, squirreltail, and needlegrass. Riparian vegetation consists principally of cottonwood, willow, and various shrubs and grasses.

The pinyon-juniper woodland zone covers extensive areas in Utah and Colorado at elevations ranging from 7,500 feet to as low as 5,500 feet. In Wyoming it occurs only in a few isolated places. When observed at great distance the zone appears to form a dark, solid belt of evergreen trees, but upon closer inspection it resolves itself into an open woodland dominated by pinyon pine, Juniper, or a combination of the two. Scattered between the trees, which rarely exceed 20 feet in height, is an understory composed of such species as bitterbush, big sagebrush, mountain-mahogany, serviceberry, cliffrose, and various herbaceous plants.

The mountain brush and forest zone occupies soil-covered slopes above 7,500 feet elevation, and is restricted almost entirely to Utah and Colorado. The lower portion of the zone has the appearance of chaparral and is dominated by such shrubs as gambel oak, mountain-mahogany, serviceberry, bitterbush, choke-

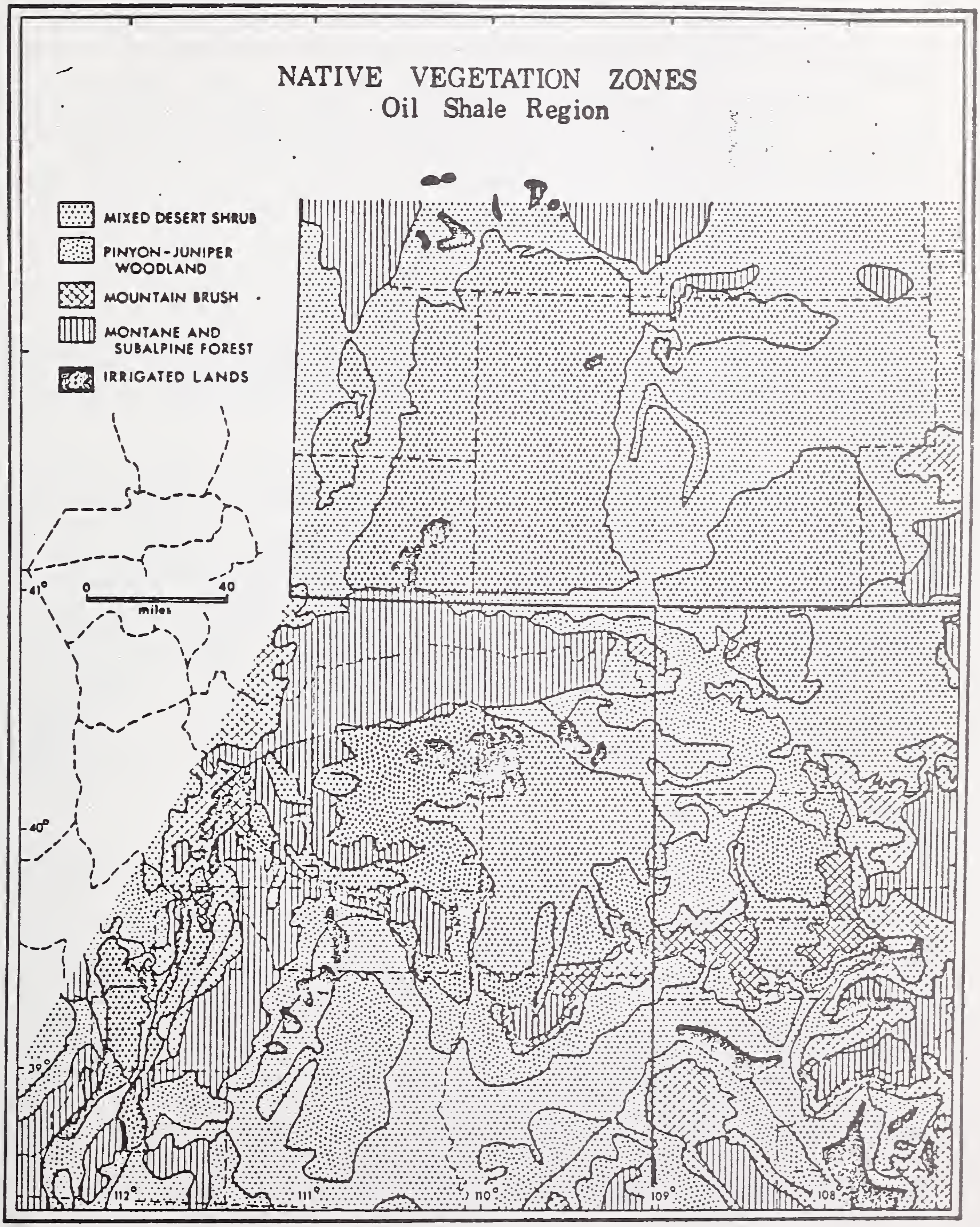

NATIVE VEGETATION ZONES
Oil Shale Region
MIXED DESERT SHRUB
PINYON-JUNIPER WOODLAND
MOUNTAIN BRUSH
MONTANE AND SUBALPINE FOREST
IRRIGATED LANDS
0
40
miles
41°
40°
39°
112°
111°
110°
109°
108°

Figure 7

cherry, cliffrose, and big sagebrush. At higher elevations the shrub complex alternates with scattered groves of aspen, lodgepole pine, and blue spruce, or gives way to subalpine forests dominated by Englemann spruce and alpine fir.

The vegetation in all three zones provides forage for domestic livestock, browse and cover for wildlife, and ground cover to retard wind and water erosion. The upper elevations are grazed during summer by cattle, sheep, deer, and other big game; the lower elevations provide criticial winter range for the same species. Rangeland productivity varies with individual sites, but in general 10 to 20 acres are required to support one animal-unit-month of grazing. Although feed requirements for game animals and domestic animals are not exactly the same, competition is sufficiently intense in some areas to pose a serious problem.

Irrigation in the Piceance Creek Basin is mostly confined to hay meadows on narrow bottomlands adjacent to the larger streams. However, the Grand Valley area southwest of the basin contains about 56,000 acres of irrigated field crops, fruit orchards, and vegetables (Leathers and Young, 1976) which might be adversely affected by air or water pollution emanating from an oil-shale industry. Hay meadows in the nearby White River Valley could also be impacted by industrial activities.

Nearly all of the irrigated acreage in the Uinta Basin lies adjacent to or north or the Strawberry and Duchesne Rivers, where the oil-shale deposits are deeply buried. About 58,000 acres of potentially irrigable land are located in the Uinta County area of thick, rich oil shales (Wilson, et al., 1968).

Irrigated acreage in the Green River Basin totaled about 100,000 acres in 1970 (Wyoming Water Planning Program, 1970). None of the shale areas contain any significant amount of land that could be cropped without irrigation.

Shale Oil Recovery and Resource Requirements

Introduction

Commercial production of liquid fuels from oil shale began in France in 1838, though patents for oil shale processing in England are dated even earlier. The Scottish oil shale industry, which dates back to 1850, grew to much larger proportions than the one in France and existed for more than a century producing fuels, waxes and chemicals. Commercial production in France stopped in 1964. Between 1850 and 1950 oil shale industries were established at various times in Australia, Estonia (U.S.S.R.), Sweden, Spain, Manchuria, the Republic of South Africa, and Germany. In more recent times Brazil has also developed a modest industry. In general, these industries have received government assistance and protection in such forms as subsidies, tax exemptions and duties on imported petroleum products. In Sweden and Germany, the shale oil industry was developed during World War II, primarily to assist in providing war time oil needs. All of the oil shale industries except those in the People's Republic of China and the U.S.S.R. have died because of inability to compete with petroleum fuels (Schramm, 1975).

That the nation needs greater energy supplies has become an axiom in today's world. The matter of where these supplies will be derived is less certain, however. To meet future energy demands, the nation will probably have to rely on its "exotic" energy resources, which may include solar energy, geothermal energy, methane generators, coal gasification, and of course, shale oil (Morse, 1976).

Oil shale certainly represents a vast energy potential. However, the shale oil resources of the Green River formation have been known for a long time, but a commercial shale industry has never been developed in the study region. In the past, the main obstacle to shale development has been economics. That is,

the shale oil has been too expensive to compete with other petroleum supplies. Even today experts point out that the production of synthetic crude oil from oil shale is at best marginally economic at world prices (Morse, 1975).

If the initial hurdles of starting a shale oil industry are overcome constraints on the growth of the industry may be severe unless sufficient advance effort is made to minimize them. Most of these potential constraints may be categorized as environmental, technological, legal, policy related, and water supply. Work is progressing on all these fronts; acceleration in some areas may be needed to avoid bottle necks if an economic climate favorable to oil shale development materializes. Research is now focused primarily on developing an in-situ oil recovery technology, developing mining methods for the deeper lying rich oil shale beds, and improving environmental protection and technology (Schramm, 1975).

Called the "rock that burns" by frontier time Indians, western oil shale is neither a shale nor does it contain oil. Instead, oil shale is an organic marlstone. It is a sedimentary rock containing solid organic materials in a mineral matrix. These organic materials constitute the source of crude shale oil. About 5 to 10 percent by weight of the organic material is bitumen, a tar like substance which is soluble in many conventional organic solvents. The remaining organic material is kerogen, a hydrocarbon molecule of high molecular weight which exhibits strong rock binding properties. The chemical properties of oil shale kerogen mean that only a minimal fraction of the organic material in oil shale can be removed by conventional solvent-extraction techniques. However, when oil shale is heated the organic materials decompose to form gaseous or liquid products, including crude shale oil. This heating process which converts the bitumen and kerogen to oil and gas, is called pyrolysis or retorting; a retort is the vessel in which the oil shale is heated (Morse, page 1, 1975).

Magnitude of the Mining Problem

While the gargantuan oil shale resources of Colorado, Utah, and Wyoming are known to exist, the problems of their eventual use are still beyond the conception of most men. As now contemplated, an oil shale industry will be the world's largest industry processing low grade minerals. Solids will be mined and handled at a magnitude not heretofore accomplished on an industrial scale (Prien, 1974). The following example, using 30 gallon per ton shale, illustrates the point; for every 2,000 pounds of shale mined and then retorted, there is obtained 230 pounds of shale oil product. Thus, approximately 82 percent of the shale mined (86 percent if the carbonaceous coating is not used as fuel) must be discarded as waste material. A 50,000 barrel per day plant will mine about 73,000 tons of shale per day (24 million tons per year), and discard approximately 59,000 tons per day (19.5 million tons per year) of waste spent shale. A projected one million barrel per day industry will require the mining of 480 million tons of shale annually which is about 70 percent of the current annual level of U.S. coal production (Prien, 1974).

All of this processing must be done in a region in which water for processing and domestic use is very limited. Finally, the shale oil produced must be transported 700 to 1,000 miles to substantial markets. Of course, the absolute numbers associated with any industrial size will depend heavily upon the method of development. The modified in-situ processing method is expected to require the movement of less processed ore per unit of oil production. On the other hand, a room and pillar underground mine with surface retorting would require not only movement of the ore from the mine to the retort but also movement of the spent shale away from the retort to a disposal area. Thus, in the latter situation the actual volume of ore movement would be doubled.

A second measure of the oil shale resources is the quantity that could be recovered using existing techniques, without considering costs. There is a

wide range of opinion regarding the quantity of those recoverable resources but a generally accepted figure is 600 billion barrels of oil using conventional mining methods. However, the size of the recoverable resource depend strongly upon the particular recovery technique employed. It is noteworthy that the recovery approach which has been utilized most in the past, room and pillar mining plus surface retorting, is constrained to using only the richest resources in the mahogany zone, a relatively thin but rich oil bearing zone extending throughout the Piceance Creek Basin. Open pit mining, strip mining, in-situ processing or modified in-situ processing all would potentially yield greater portions of the total oil resource (Rattien and Eaton, 1976).

Mining Methods

Any mining method which utilizes surface retorting must somehow remove the shale from its current location and break it up for retorting. The oil shale can be mined either from the surface using open pit mining or underground using long wall or room and pillar methods. The choice of mining method depends on several factors such as the overburden depth, seam thickness, deposit size and other site-specific geological characteristics (Morse, 1976).

Underground mining

In room and pillar mining a portion of the ore body is removed to form large rooms. The rest of the ore is left in place as pillars, to support the roof. Relative sizes of pillars and rooms are determined by physical properties of the ore, overburden thickness and height of the mine roof (Sladek, 1975).

The total quantity of material recoverable from an underground mining operation depends upon several factors, including depth of deposit, grade of deposit, rock structure and geological structure. The fraction of the ore body that must be left as pillars to support the mine roof and all overlying beds can range from as little as 20 percent in shallow deposits of highly competent rock, to as

much as 80 percent in deeper, less competent rock (Ashland, 1976). As the thickness of the mining zone increases, the area of the support pillars must increase and the fraction of the total zone which can be extracted decreases.

The original plans for development of the C-b oil shale tract called for mining only within the mahogany zone. The pillar dimensions were expected to range from 50 feet square to 150 feet square. Room spans were expected to fall within the range of 40-60 feet in horizontal dimension of the height of the rooms ranged from 45 to 75 feet. Figures 8 and 9 illustrate a general schematic for a typical underground mining process.

The major advantages of room and pillar mining expressed by the detailed development plan for the C-b tract plan are: highly flexible in that it can be modified easily throughout the life of the mine to suit conditions, equipment or technological developments; adaptable to a high degree of mechanization; high degree of productivity because of the number of working areas available; relatively easy to ventilate; mine development is a production operation since it also takes place in the mining zone; the mine can be designed to minimize the possibility of surface subsidence. The major disadvantages of room and pillar mining are listed as being a high cost system for roof support and providing relatively low extraction ratios. The overburden above the proposed mining zones of the C-b tract ranges from 900 to 1300 feet. The overall extraction ratio was expected to be in the 30 to 50 percent range depending primarily on the height of the mining zone.

Surface mining (Open Pit)

Surface mining is economically attractive for large low grade ore deposits because it permits high recovery of the resource and provides ample room for large and efficient mining equipment (Sladek, 1975). Although large equipment can be used in room and pillar mining, resource recovery from such a mine cannot

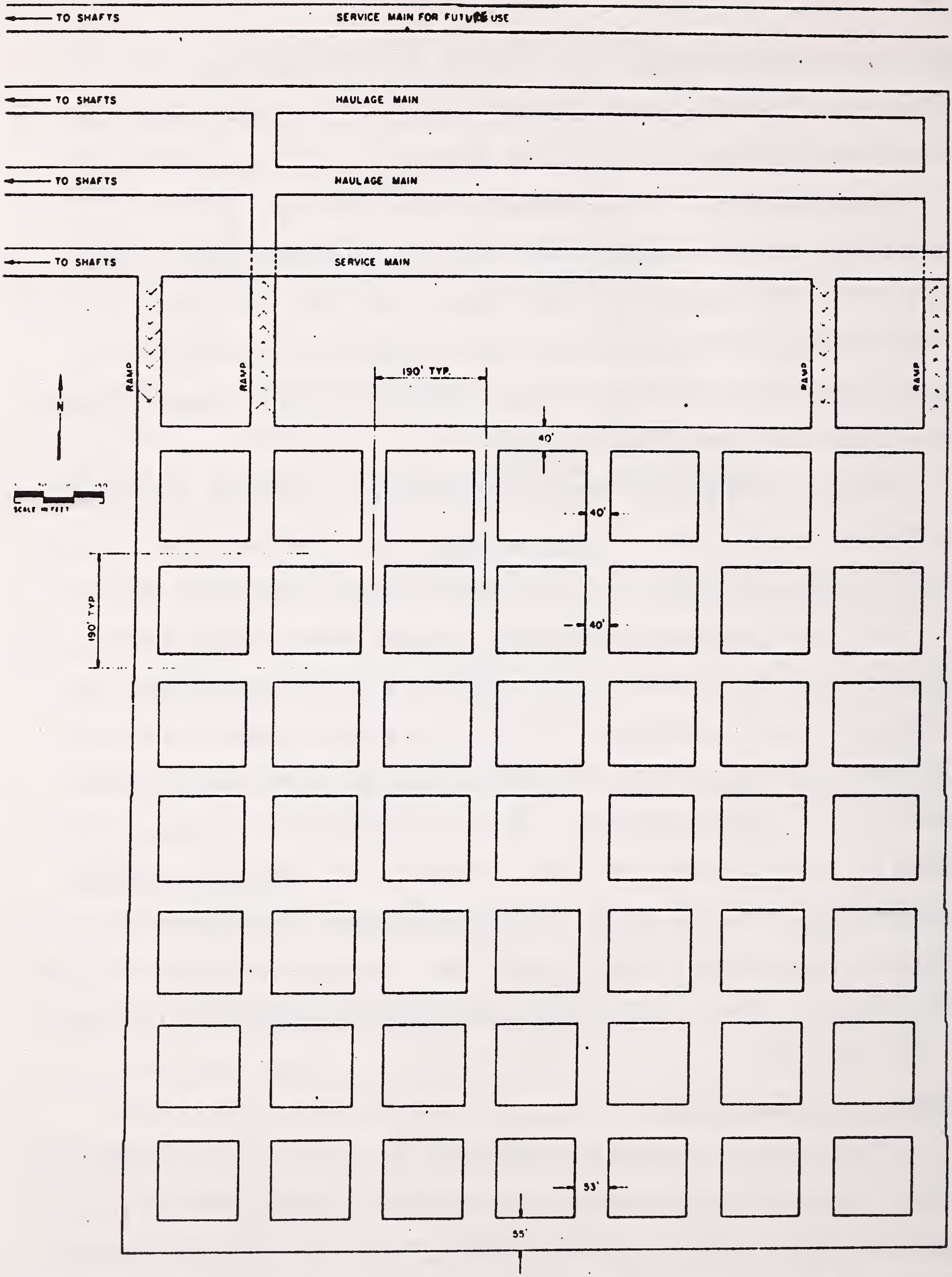


Figure 8- Development Mine Layout for Room and Pillar Mining

Source: Ashland, Inc., 1976.

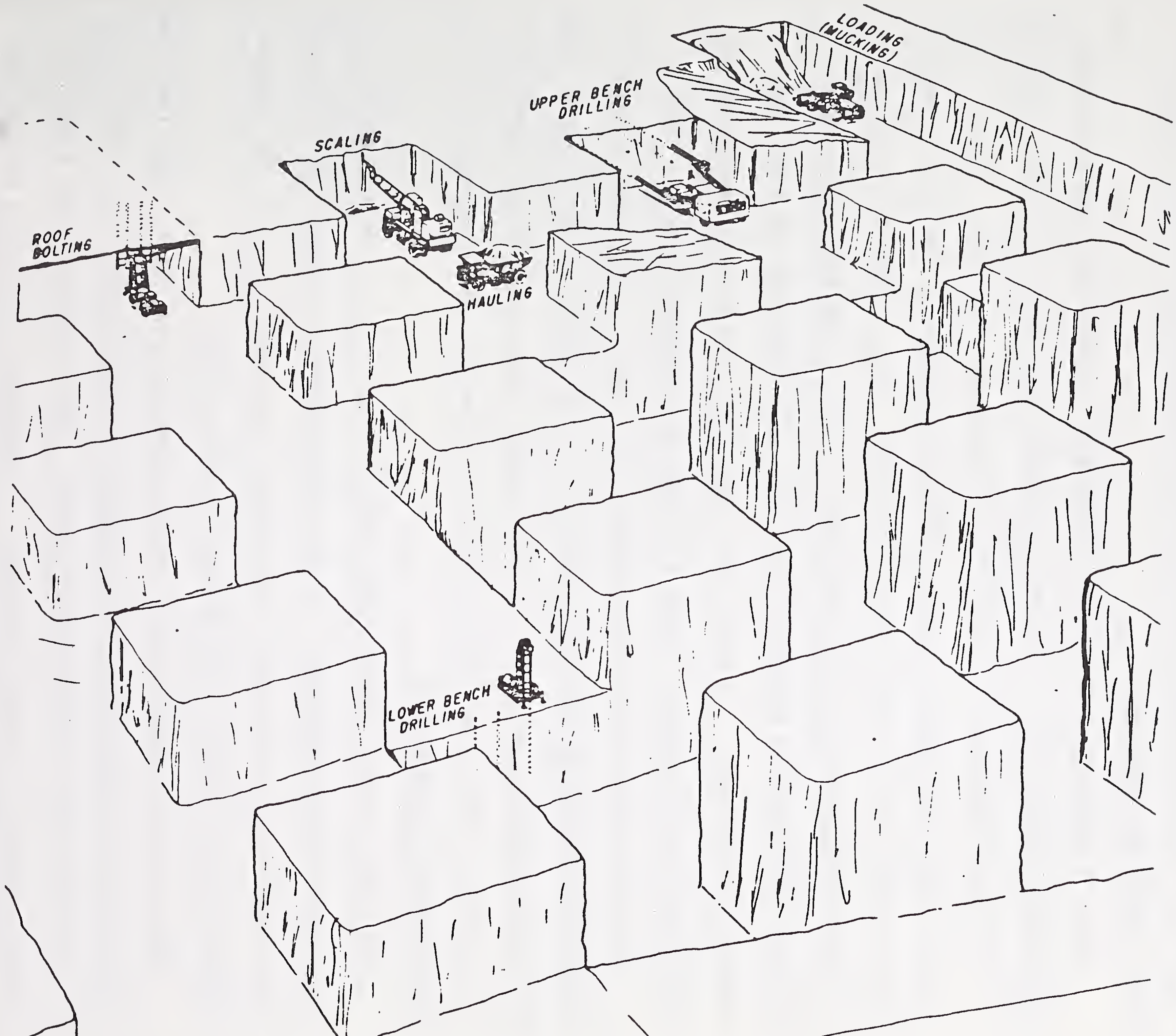


Figure 9 -- Room and Pillar Mining Concept

Source: Ashland, Inc. 1976

equal recovery from an equivalent open pit. The proposed underground Colony Mine would recover 60 to 70 percent of the oil shale in a 60 foot high seam. An open pit mine could theoretically recover almost 100 percent of the shale from the entire 2,000 foot thick seam.

Open pit mining is conceptually simple and its technical aspects are well understood (Sladek, 1975). In open pit mining a huge hole is dug down from the surface into the body until the bottom of the ore bed is reached. Walls of the hole are then carved away so the hole diameter increases as the mine is worked. Open pit mines for oil shale will be very large. One has been described for a proposed 80,000 barrel per day shale plant. In its prime the proposed pit would be 10,000 feet in diameter at the top, 3,000 feet deep and 4,000 feet in diameter at the bottom. To reach this stage 35 billion feet of overburden and 73 billion feet of broken oil shale will have to be removed (Sladek, 1975).

One factor inhibiting surface mining of oil shale is the great thickness of overburden covering the rich shale deposit. In the center of the Piceance Creek Basin the 2,000 foot thick shale is buried under about 1,000 feet of overburden. This overburden has to be removed before oil extraction can commence.

In-Situ Mining and Retorting

Oil shale can also be retorted in-situ, or in place. In-situ retorting involves two critical operations: 1) the establishment of permeability in the oil shale formation to create paths for movement of gas and liquid; 2) the introduction and control of heat in the formation (Morse, 1976).

Some oil shale deposits are naturally permeable and, hence, would lend themselves to in-situ processing. Those deposits in the Piceance Creek Basin which have contained water soluble saline minerals, such as dawsonite and nahcolite, could be amenable to in-situ processing. Groundwater circulating through the natural fissures in the beds has leached out the soluble minerals and left voids

in the deposits. These permeable areas would then be useful for in-situ retorting once the saline groundwater is pumped from the formation (Morse, 1976).

However, most oil shale deposits are not sufficiently permeable for large scale in-situ retorting. Consequently, the permeability would have to be increased by enlarging existing fractures or creating new ones through some means of blasting. In theory, a pattern of bore holes would be drilled into the shale and the formation would be fractured hydraulically or with liquid chemical explosives. Ideally, the fractured oil shale would be broken into small pieces or rubble that would be about the size of the crushed oil shale fed into a surface retort. However, the achievement of this goal is very difficult.

After creating permeability, heat is introduced into the formation. The sources of heat may include combustion of the oil shale itself, initiated by using natural gas sustained by the injection of air; hot natural gas or methane; hot carbon dioxide; hot solvents; or combinations of two or more of these (Strang, 1974). The combustion front of hot liquids or gases are then swept horizontally through the formation to drive retorted shale oil out of one or more of the bore holes (Morse, 1976).

"Pure" or true in-situ technology, which involves no mining, is still under experimental development as an oil shale retorting method and it has only been marginally successful to date. However, in-situ processing should offer many advantages over underground mining and surface retorting. These include: as much as two-thirds fewer people to operate the process; one-half to two-thirds the amount of water is required; essentially no spent shale is generated for disposal; the capital investment requirement is reduced (Project Independence Oil Shale Task Force, 1974 as taken from Morse, 1976).

In-situ processing may also allow increased resource recovery from low grade oil shale deposits. Most surface retorts require 25 to 30 gallon per ton oil shale. However, nearly 1.2 trillion barrels of the total 1.8 trillion esti-

mated to be in the total oil shale resource consists of low grade deposits with seams more than 10 feet thick having an average yield of only 15 to 20 gallons per ton. These low grade deposits will probably never be recognized or used with conventional mining techniques but might be exploited once in-situ techniques are developed (Morse, 1976).

Modified In-Situ Mining and Retorting

Modified in-situ processing is actually mine-assisted-in-situ retorting combining the primary advantages of both underground and in-situ mining processes. A vertical, underground retort is prepared by mining enough oil shale from within the shale deposit to create a room (Morse, 1976). Blast holes are then drilled outward from the room into the formation. The desired permeability is obtained by detonating explosives in the blast holes. The broken rock fills the void space, creating a chimney of rubble. The mine tunnel is sealed and gas supply and exhaust lines are installed. The top of the shale rubble is then ignited through bore holes drilled from the surface. During retorting, shale oil flows to a sump at the bottom of the underground retort and is then pumped to the surface. The oil shale mined from the cavity, about 15 to 25 percent of the retort chamber, can be retorted using surface retort methods.

Development plans for the C-b tract are now proceeding under the assumption that the modified in-situ process will be used. Occidental Oil Company has developed the intended technology on private lands over the past several years. The suggested process involves mining about 20 percent of the rock. The retort interval of primary interest at the present has a vertical dimension of 310 feet. This interval starts just below the top of the mahogany zone. Individual retorts are expected to be 200 by 200 feet square and 310 feet high. The commercial in-situ operation will produce approximately 57,000 barrels of oil per day from a total of 40 operating retorts. The surface process facilities associated directly

with retort products include oil and water separation equipment, gas treatment including both product gas blowers and hydrogen sulfide removal and steam generation from treated product gas. The quantity of mined out raw shale will be approximately 41,000 tons per day as compared to 66,000 tons per day of spent shale in the original development plans for a 50,000 barrel per day plant using underground mining methods.

It is expected the removal of mined out shale will be from the mahogany zone or the richest of that which is available. Thus, bringing to the surface 41,000 tons of rich shale daily would provide the additional possibility of surface retorting about 27,000 barrels of oil per day. Thus, the creation of a 57,000 barrels per day modified in-situ process may actually produce over 80,000 barrels of oil per day in the long run.

If there are not plans for surface retorting of mined shale it is most likely that the void space for the in-situ retort will be created from the leanest or most barren portions of the shale deposit. In this case, the mined out portion of the shale would be disposed of by filling canyons on the surface. This disposal site would then be revegetated in much the same manner as would be required of the compaction and revegetation of spent shale deposits.

This process has some economic advantages. For one, there is no disposal of spent shale unless a surface retort is used. The disposal of mined rock presents no major ecological problem since it is the same as the exposed cliff in many parts of the area (McCarthy, et al., 1976). This material will be dumped into the canyons near the oil shale mine. Another ecological advantage is that there is less water used in this operation. Cooling and disposal of spent shale is not required. The only water needed is for mining and the bulk of this will come from the water produced during retorting and mine zone dewatering. Also, this system does not require the shale oil to be upgraded before

being transported to processing facilities. There are a number of unanswered questions regarding this technique, however. Some people believe there will be some serious groundwater problems develop in some sites under in-situ mining.

Retorting Methods

The term "retorting" signifies the process of adding heat to the shale to decompose its organic material into gas and liquid hydrocarbons (WRSP, 1976). There are two basic categories of retorting: in-situ and above ground. In the in-situ process thermal decomposition takes place below the ground. In the above ground process retorting is performed in large vessels called retorts in which heat is applied to crushed shale. Two types of retorting processes exist: in one the retort is direct heated (D.H.) and in the other, the retort is indirect heated (I.H.).

A direct heated retort is one in which oil is recovered from the shale by means of the heat that is generated entirely within the retort. Carbon on the shale and some gas are burned within the retort. This combustion heats the shale, causing oil and gas to be released and the products flow out of the retort.

An indirect heated retort is one in which gas and oil are recovered from the shale by means of heat which is generated outside the retort. A heat carrier (either gas or solid) would be circulated continuously through the retort to heat the shale. The heat is supplied to the carrier by burning some form of fule in a heater. As the heat is applied to the shale, oil and product gas are released from the retort. The fuel that is used in the heater of an indirect process may be any conventional fuel.

There is a product gas generated from both the D.H. and I.H. retorting methods. In the case of the D.H. retort the gas will contain a significant amount of nitrogen, and hence, the product gas from a D.H. process is a low

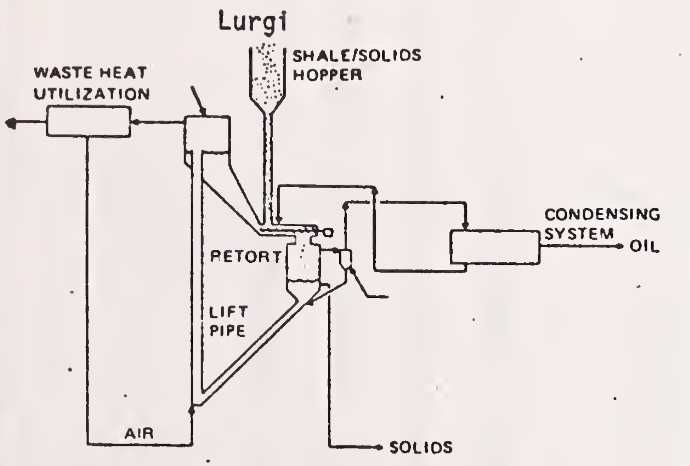
BTU gas. On the other hand, the product gas from an I.H. process is a high BTU gas. A high BTU gas has several advantages over a low BTU gas. It is a better fuel, more easily transported, and it is more adaptable to further processing. It is suitable as a plant feed stock or as a marketable heating gas.

Before the raw shale can be processed in an aboveground retort, it must be crushed. The size of the crushed raw shale that can be processed varies from one type of retort to another. Some retorts require extremely fine particles (from approximately ½ inch maximum dimension to a powder), while others can handle only coarse shale greater than approximately one-half inch. Approximately 10 to 15 percent of coarsely crushed raw shale feed will unavoidably be smaller than one-half inch. This does not mean that 10 to 15 percent of the oil content of the mined shale will be lost by retorting systems that cannot process this fine shale, for such fine shale contains somewhat less oil per unit than the coarse shale, and retorting systems operate at different recovery efficiencies.

The major retorting processes to be described here are: Lurgi, McDowell-Wellman, Paraho, Petrosix, Tosco-II, Union Oil and Bureau of Mines. These are all taken from the White River Shale Project detailed development plan (WRSP, 1976). Since the Bureau of Mines process is essentially an early version of the Paraho process it will not be described here. Simplified diagrams of each of the six schemes for above ground retorting are provided in Figure 10. Table 3 summarizes the major features of the retorting systems that are being considered at this time.

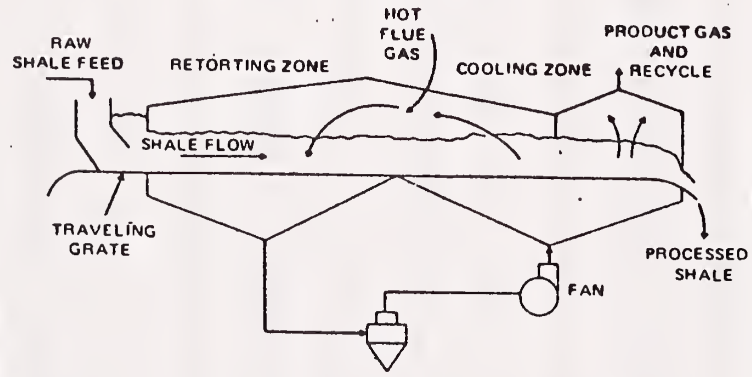
The Lurgi and Tosco-II processes are capable of processing all of the shale that is mined. In the Paraho, Petrosix, and Union schemes, the preferred raw shale feed particles are one-half inch and larger. There is not, however, necessarily any correlation between the ability to process fine shale particles and the final yields of oil and gas from the raw shale feeds.

Lurgi



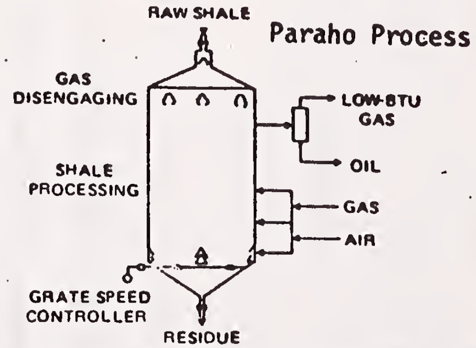
This method processes minus ½-inch shale in the IH mode. Carbon in the processed shale is burned in the lift pipe, and the hot circulating processed shale from the lift pipe mixes with raw shale in a screw conveyor to bring about an intimate mixing of the solids.

McDowell-Wellman Process



This process is operated as a DH retort and can accept both fine- and coarse-grade shale. This retort is a doughnut-shaped structure: shale is carried on a traveling grate in a circular path, and is successively heated and cooled by a gas passing through the grate. In the retorting zone, a gas/air mixture is combusted for heating the shale.

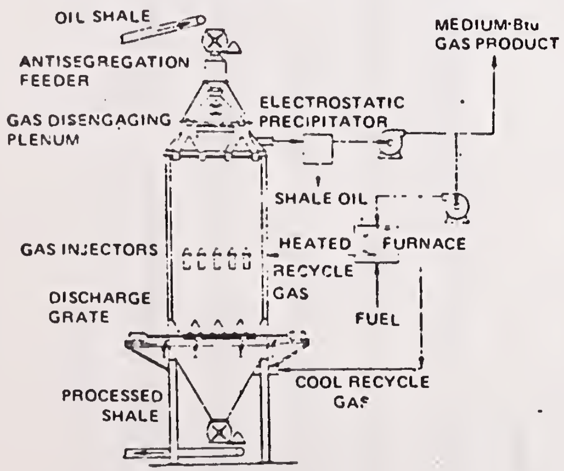
Paraho Process



There are two types of Paraho processes: DH and IH. Both methods process minus 3-inch plus ½-inch shale in a vertical shaft retort in which the solids flow downward. In the DH retort, the gas/air mixture is injected at three bed levels and flows upward. The product oil leaves the top of the retort as an oil mist carried by the product gas. In the IH retort, heat is supplied ~~by a~~ heater which heats a gas stream before injection into the retort.

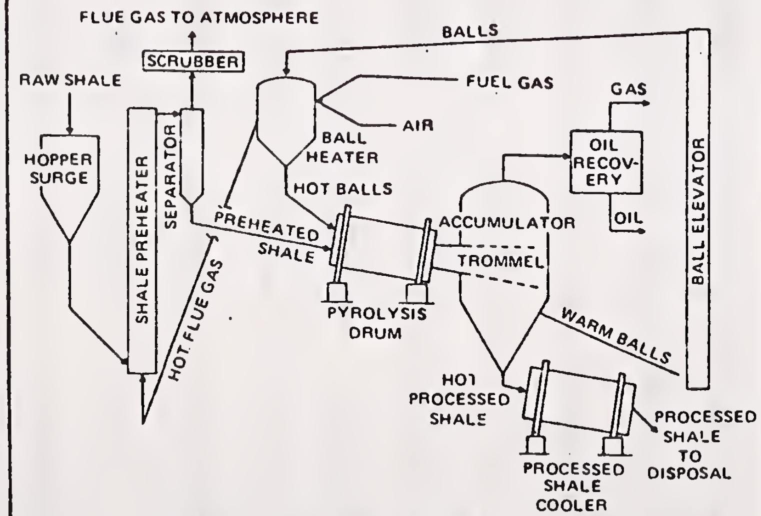
The indirect heated retort will have no air injection, and the recycle gas will be heated in a separate furnace external to the retort. The heated gas will be injected into the shale bed at multiple levels. The retort will be almost identical to the direct heated retort.

PETROSIX PROCESS



The Petrosix method processes minus 3-inch plus ½-inch shale in a vertical-shaft retort. Within the retort, rock flows downward and the heating gas flows upward. Heat for the retorting is applied by a gas heated in a furnace outside the retort, and the hot gas is injected into the retort at one bed level.

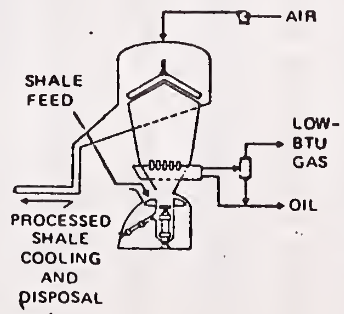
TOSCO II PROCESS



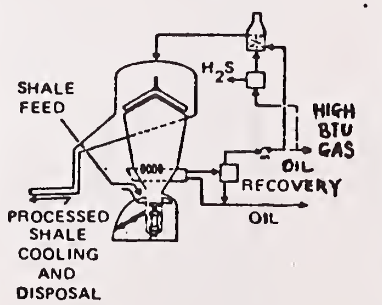
The TOSCO II method processes minus ½-inch shale in an IH retort. The shale is heated to retorting temperature in the pyrolysis drum by hot ceramic balls. The mixture of shale and ceramic balls is then separated in a trommel.

Figure 10. Surface Retorting Processes.

UNION OIL TYPE "A" PROCESS



UNION OIL TYPE "B" PROCESS



The Union Oil method processes minus 3-inch plus ½-inch shale in a vertical shaft retort. Within the retort, rock flows upward (through the action of a rock pump) and the heating gas flows downward. The retort can be either DH or IH. The Type A retort is DH; the Type B retort is IH.

Source: WRSP, 1976.

Table 3 -- Comparison of the Major Retorting Processes

	Lurgi	McDowell-Wellman	Paraho		Petrosix	Tosco II	Union Oil	
							Type "A"	Type "B"
Type of heating	IH	DH	DH	IH	IH	IH	DH	IH
Resource recovery								
Approximate raw shale size that can be processed	Minus ½ in.	Minus ½ in.	3½ in.		3½ in.	Minus ½ in.	3 - ½ in.	
Some carbon in processed shale is used for heating	Yes	No	Yes	No	No	No	Yes	No
Product gas quality	High Btu	Low Btu	Low Btu	High Btu	High Btu	High Btu	Low Btu	High Btu
Estimated yields/ton of raw shale								
Oil (% of Fischer assay)	100	90	95	100	100	100	90	100
Gas (1,000 Btu/ton)	800	500	650	550	600	700	1,000	1,000

Environmental considerations

Processed shale	In the retorting of oil shale, the chief environmental problems are caused by the processed shale produced during retorting. These problems are similar for all retorting processes--leaching of salts at the disposal site, trace metals in the shale, shale permeability, compaction properties of the shale, and the stability of the shale pile--but they are more severe with finer particles.
Product gas and crude shale oil	For a discussion of product gas and crude shale oil, see Section 7.8, "Shale Oil Upgrading." (WRSP, 1976)
Dust	Dust control will be required in each of the retort facilities. Those processing finely graded shale are expected to have more severe dusting problems.
Water consumption	The difference in water consumption between retorts is negligible, except that fines-type retorts should require more water for dust control.

Source: WRSP, 1976

The Lurgi I.H. retort and all of the D.H. retorts except the McDowell-Wellman use carbon on the shale as the heat source to extract oil from the shale. In the Tosco-II, Petrosix, Paraho I.H., and Union Oil I.H. retorts, retorting heat must be obtained from conventional fuels. Thus, the D.H. retorts and the Lurgi I.H. retort produce more of the total available energy from raw shale than the aforementioned I.H. retorts.

Disposal of processed shale is a major environmental problem in the retorting of oil from shale. The processed shale can have different characteristics with different degrees of environmental problems. Processing fines generally presents greater problems of disposal and dust control.

For the various retorting alternatives. the product gas and oil produced are also slightly different as indicated in table 3.

It must be noted at this time that none of the retorts described here have been built to a commercial capacity. The largest retort of any kind tested so far under actual field conditions was a Union A retort, which achieved a throughput of about 1,200 tons of shale per day. In a commercial operation it is expected that each retort would process 8,000 to 13,000 tons of oil shale per day and produce between 5,000 and 9,000 barrels of crude shale oil per day (Morse, 1976).

The crude shale oil produced from a surface retort differs from conventional petroleum crude oil in several respects. In general, crude shale oils are classified by conventional petroleum standards as dense, viscous liquids with a high pour point, a moderate sulfur content and a high nitrogen content. Table 4 compares the properties of shale oil produced by the different retort processes with two types of conventional petroleum: a heavy high sulfur California crude and a high quality Utah crude (Morse, 1976).

The high pour point and high viscosity of most shale oils result in storage

Table 4 --Properties of Shale Oils and Petroleum Crude Oils.

Retort Process	Gas Combustion Retort	Union "A" Retort	Union SGR* Retort	Heavy Sour** Crude Santa Maria Valley California	High Quality Crude Aneth Field Utah
Pour Point (^{o}F)	85	75	70	20	40
Viscosity (SUS)	310 at 100^{o} F	180 at 100^{o} F	Not Available	215 at 122^{o} F	37 at 100^{o} F
Sulfur (weight %)	0.69	0.71	0.7	5.0	0.14
Nitrogen (weight %)	2.13	1.89	1.8	0.6	Not available

*Steam-gas recycle

**High sulfur content

Source: Sladek, 1974, p. 6., as taken from (Morse, 1976).

and transportation problems. If the oil is not upgraded the storage tanks and pipelines must be heated so the crude shale oil will flow. Additionally, the high nitrogen and sulfur content of the shale oil adversely affects the refining of petroleum products.

One proposed upgrading facility, having an input of approximately 55,000 barrels of crude shale oil per day, would produce 47,000 barrels of low sulfur syncrude per day, 4,330 of liquified petroleum gas (LPG), 135 tons of ammonia, 173 long tons of sulfur, and 800 tons of high ash petroleum coke (Morse, 1976).

Water Requirements for Oil Shale Production

In the past it has been assumed that waste disposal and shale oil upgrading operations would account for roughly 60 percent of the water requirements as shown in figure 11. If the water consumed by these activities could be reduced in some manner it is possible that the scale of the industry could be increased over past estimates that were assumed to be limited by water supplies. For example, in waste disposal operations most of the water is used in compacting the spent shale (Morse, 1976). This water requirement can be reduced by using only the minimum water necessary to prevent dust problems in the initial stages of compaction and then gradually increasing the percentage of water in the later stages of disposal. Recent experience with spent shale from the Paraho retort, which does not use the finely ground shale, indicates that shale oil disposal could be accomplished without the use of water. Of course, the revegetation would still require water inputs.

Water requirements could also be reduced by transporting the heavy, thick crude oil via a heated pipeline or an insulated or heated tank car to another area. This would eliminate the need for local water use in upgrading. Finally, local water requirements could also be reduced by importing water from other areas or relaxing reclamation requirements.

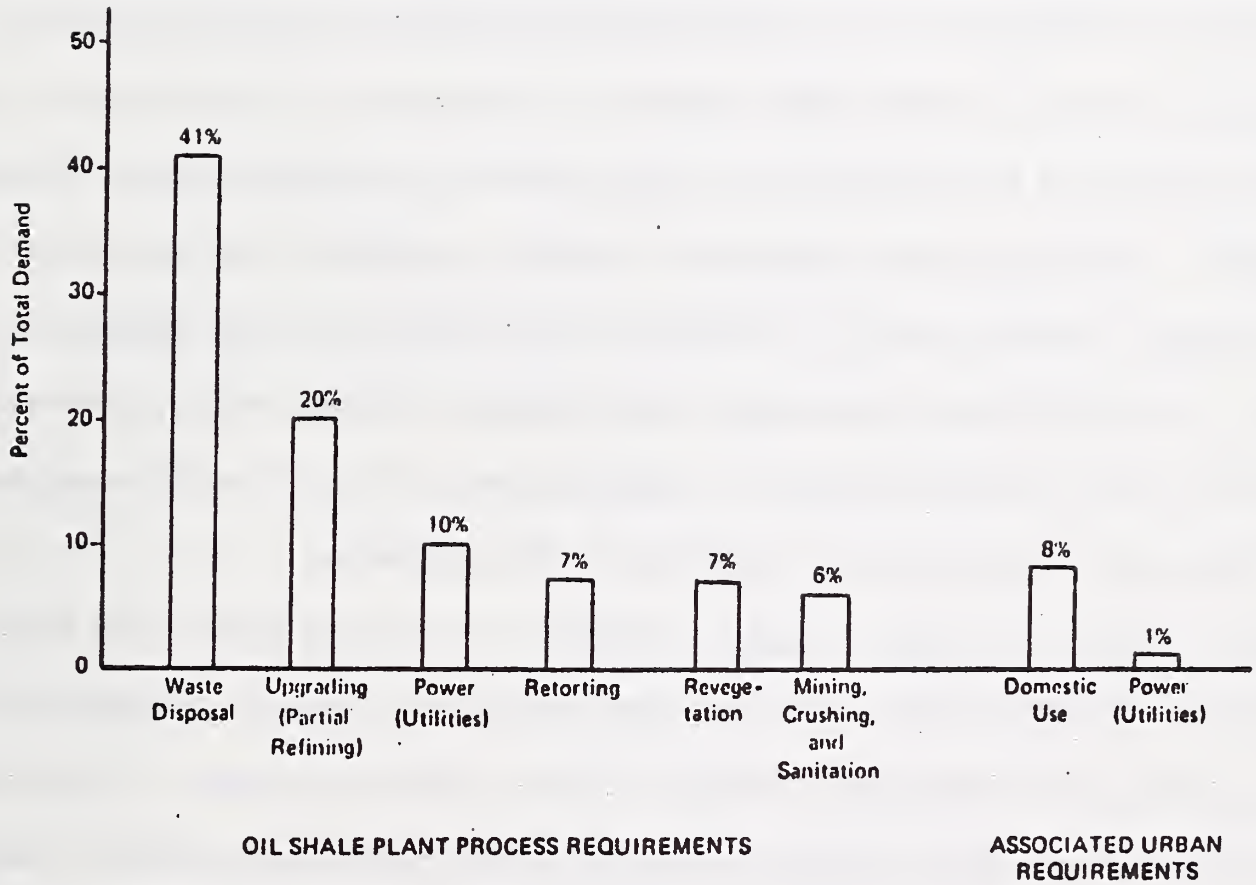


Figure 11--Process Water Requirements for a 50,000 BPD Plant, underground mining
Source: Project Independence, 1974, p. 295 (Morse, 1976)

A recent estimate of water consumption for a commercial plant is provided by the updated Detailed Development Plans for the C-b tract using a modified in-situ mining technique. The water requirements for this process, estimated for a 57,000 barrel per day plant without surface retorting, would require a water supply of 2,500 gpm. (Ashland, 1977). This equals about 11 acre feet per day or 4,036 acre feet per year. The estimated mined water available during full operation is expected to be 2,000 gpm. or less. From this calculation it may be seen that water needs during the plant commercial operation phase are to be approximately 2,500 gpm. of which nearly 2,000 gpm. would be provided by the mining activity itself. Usage of water in the original DDP showed a net plant requirement of 5,500 gpm. for an underground mine room and pillar method or about twice as much as recent plans require. The capacity of the plant at that time was expected to be 50,000 barrels per day of oil using the Tosco II retorting process. The more recent estimates of water consumption for the modified in-situ process include uses for all plant activities plus steam generation for retorting, for heating and processing requirements, drinking water, evaporation losses and use of irrigation water in revegetation. Off site water requirements for ancillary activities are not included in this estimate.

The Rio Blanco oil shale project for the C-a tract estimated that after full development of 55,800 barrels per day there would be an annual consumption of water of 10,000 acre feet (RBSP, 1976). Of this total 41 percent is allocated for use on processed shale disposal, 30 percent for retort and vent gas losses, 25 percent for cooling water losses, the remaining 5 percent being chemically converted or lost in miscellaneous manner. The RBSP also indicates that the raw water intake of about 8,300 acre feet per year would be provided from ground water once the development reaches full scale operations. Additionally 450 acre feet per year would be water produced in the retort process. Thus, it is not expected that development of the C-a tract through open pit mining would require an outside

water supply.

The purpose in describing these alternate sources of water consumption is to show the range and variability of estimates that have been provided in the past. Water required for shale disposal and retorting could be near zero rather than at the high levels displayed by most of the past publications. This water requirement depends largely upon the type of plant that is built. It is the opinion of this author that a deliberately high or conservative estimate of water needs has been provided in the past in order to assure the industry of having sufficient water once development is underway. In actual practice it is probable that a portion of the water indicated for use in the various activities of oil shale mining and processing could be eliminated or reduced substantially. Table 5 summarizes water consumption data from the various sources of information encountered in the course of this study. The range of numbers for each activity presented in this table represent an assumed practical limit on water use that could be achieved under full development. Implicit in the lower range of numbers are assumptions that technologies applied would be the most water efficient possible. It has been shown that it is possible to dispose of processed shale from the Paraho direct heat process retort without the use of water for compaction or dust control. The figures shown in table 5 are within the practical limits of those expected for necessary externally supplied water after full development. In the near future most water requirements in the Piceance Creek Basin could be supplied from the dewatering of the mine zone or from groundwater pumping below the mine zone. Other areas may require imported water from the very beginning. If these conjectures are correct it is probable that a million barrel per day industry utilizing water supplies somewhere in the range of 65 to 120 thousand acre feet of water could be developed.

Land Requirements

One of the primary concerns expressed by people in the area of oil shale

Table 5 --Water Consumption per 1000 barrels per day of shale oil produced -- acre feet per year.

Process Requirements	Underground Mine (Room & Pillar)a/	Surface Mine (open pit) a/	In Situ a/	Modified In Situ b/	Mod. In Situ w/processing of void shale c/
Mining and crushing	7-10	7-10		2- 3	1- 2
Retorting	12-15	12-15		3- 4	5- 7
Shale Oil Upgrading	29-44	29-44	29-44	19-29	19-29
Processed Shale Disposal	58-88	58-88		17-27	25-35
Power Requirements	15-20	15-20	15-36	10-22	9-18
Revegetation	0-14	0- 7	0-14	0- 9	0- 7
Sanitary Use	0- 1	1- 2	0- 1	0- 1	0- 1
Sub Total	121-192	122-184	44-96	46-96	59-99
Associated Urban					
Domestic Use	13-18	11-15	14-17	14-17	11-15
Domestic Power	1- 2	2- 3	1- 2	1- 2	1- 2
Sub Total	14-20	13-18	15-19	15-19	12-17
Total	135-210	135-202	59-115	61-115	71-116
Average	174	168	88	88	94

a/ Adopted from USDI, 1974

b/ Estimated distribution from USDI, 1974 and quantity from Ashland, Inc., 1977.

c/ Estimated as a combination of other methods.

development is the potential land disturbance by the activity of extracting oil from oil shale. Table 6 has been constructed to show the total land disturbance expected for alternative mining techniques. The figures in this table are expressed in terms of acres per 1,000 barrels per day of production. For example, underground mining techniques would require approximately 3 acres per year per thousand barrels per day production of new disturbance. The total disturbed lands at any one time per 1,000 barrels per day for this process would be about 35 acres. Land possibly affected by subsidence could be substantial in the long run but no estimates of this effect are available.

Using the figures in table 6 we could assume that a one million barrel per day industry would disturb approximately 30,000 acres of land in the area at any one time for the purpose of oil shale production. These figures do not include estimates of land requirements for the increased population that would be induced by oil shale development. However, the figures do include all offsite needs including roads, pipelines and storage facilities.

Raymond Anderson (Economic Research Service, Fort Collins, Colorado) has estimated the land base required to accommodate the population growth in various areas of Colorado. For the upper Colorado River mainstream and the northwest region which include all of the oil shale areas of Colorado, expected population growth due to energy development will be largely concentrated in relatively dense urban areas. The development will initially occur through the process of trailer or mobile home developments. It is estimated that the land requirement for population change will be in the range of .1 to .158 acres per capita. These estimates of land use will be added to those for actual energy development shown in table 6.

Manpower Requirements

The major socio-economic impacts associated with commercial development of an oil shale industry would be: 1) the population growth resulting from the

Table 6 --Total Land Disturbance for alternative mining technique -- acres per 1,000 barrels per day production a/

	Underground Mining Room & Pillar	Surface Mining (Open Pit)	In Situ	Modified In Situ	Mod. In Situ with surface processing void shale
Annual disturbance b/	2 - 4 d/	2 - 3 f/	1 - 2 g/	2 - 3 e/	2 - 4 h/
Total disturbance c/	31 -41 d/	26 f/	6- 30 g/	26 e/	22 h/
Expected value					
Annual disturbance	3	2.5	1.2	2.5	3
Total disturbance	35	26	15	26	22

a/ Includes only on-site and off-site needs for actual oil shale production facilities. Does not include land space for population increases.

b/ New area assumed to be disturbed per year with an equal amount revegetated each year.

c/ Area assumed to be disturbed at any point in time after full scale development.

d/ Source: Ashland Oil, Inc., 1976.

e/ Source: Ashland Oil, Inc., 1977.

f/ Source: Gulf Oil Corp., 1976.

g/ Source: Morse, 1976.

h/ Estimated as an adjustment to the modified in situ process.

induced work force required for construction and operation of an oil shale complex; 2) secondary or induced population growth required to provide goods and services to the energy-related workers and their families; 3) the demand for housing and municipal services generated by this growth; 4) the impacts on the local and regional economy, including new public resources and expenditures to provide the social overhead services required for the changes in population. As the shale oil related population grows, the region's need for housing, schools, roads and all other government services will also increase (Morse, 1976).

The entire range of effects of induced employment and population from oil shale production is beyond the scope of this report. It will necessarily be sufficient to indicate the number of people that will flow into the region due to development and to describe some of the development problems that could occur as a result. In general, the region of shale oil resources in the tri-state area is sparsely populated. The region is supported by ranching type agriculture with all of the attributes thereof. A full scale oil shale industry of 1 to 2 million barrels would induce substantial changes in this type of economy. There would have to be large investments in new roads, schools, courthouses, airports, sanitary and water facilities, and health facilities, to name a few. These requirements for new capital investments will be far beyond the ability of the local tax base to support. Thus, there will be requirements for compensation in some form to the local affected communities.

The relationship between the number of energy induced workers and other population and employment effects in the local region are expressed in terms of multipliers. Table 7 shows estimated manpower requirements for construction and operation of oil shale plants of various types. Because of the extreme temporary nature of the construction employment (2 to 3 years for peak employment in most cases) it was assumed that a service employment multiplier of 0.5 would adequately reflect the induced employment by construction workers. Because the full produc-

Table 7-Manpower requirements, induced employment and total population for alternative mining techniques--manyears per 1,000 barrels per day output.

	Underground Mining Room & Pillar	Surface Mining (open pit)	In Situ	Modified In Situ	Modified In Situ w/surface processing of void shale
Direct employment					
Peak construction	39 a/ 66 b/	39 c/	30	51 e/	50 f/
Full production	11 a/ 23 b/ (21)	19 c/	12 d/	28 e/	25 f/
Induced employment					
Peak construction g/	30	19	15	26	25
Full production h/	30	28	18	42	38
Total employment					
Peak construction	90	58	45	77	75
Full production	51	47	30	70	63
Industry average	61	50	34	72	66
Total population j/					
Peak construction	162	104	81	138	135
Full production	112	103	66	154	139
Industry average k/	125	103	70	150	138

a/ Source: WRSP, 1976.

b/ Source: Ashland Oil, Inc., 1976. Figure in parenthesis is used for further calculation

c/ Source: Gulf Oil Corp., 1976.

tion employment would be much more stable and would require greater levels of services for long term employment in the region it was assumed that a service multiplier of 1.5 would reflect the full production employment multipliers.

Similarly it was assumed that because of the temporary nature of construction workers the level of population induced by such employment would be lower than under full production. As a result, it was assumed that population multipliers for construction period employment would be 1.8. That is, for every job either direct or induced for the region there would be an additional 1.8 increase in the population. Again, because of greater stability in the full production employment it was assumed that the population multiplier for this period would be 2.2.

Costs of Oil Shale Production

Two factors which influence the costs of shale oil production are capital investments and maintenance requirements. Rattien and Eaton (1976) have estimated shale oil production costs from several separate studies conducted in the past. A variety of institutions sponsored these studies including government research laboratories, industry groups, private consultants, and construction firms. Table 8 identifies the major studies of this group and provides a brief description of the type of mining process considered in each case. It is difficult to compare the results of the studies because each has a unique set of engineering, productivity and economic assumptions.

Rattien and Eaton did make an attempt to standardize certain assumptions underlying each of the reported cost studies. For example, it was assumed that each facility would provide extraction and upgrading potential. Two sets of base year dollars were used: April, 1974 and 1978. Plant reliability was assumed to be 85 percent with 15 percent down time for maintenance and repairs. The plant lifetime was 15 years. All costs are expressed in terms of dollars per barrel produced. Other assumptions in the studies were left intact. In particular Rattien and Eaton did not reevaluate reported costs in terms of a standardized discount procedure or a discount rate. Each study utilized its own discount rates and costs would no doubt change if these were standardized.

Table 9 gives the nominal costs for producing shale oil from each of 18 studies. Production cost estimates for underground extraction plus surface retorting ranged from \$3.31 to \$5.31 per barrel in 1974. Stated in 1978 dollar costs these same figures would fall between \$6.18 and \$10.27 per barrel. Estimates made by government groups were lower than those made by representatives of the oil industry. The highest cost estimates (in 1974 dollars) were made by the construction consultants designing specifications for a full scale shale oil facility.

Table 8-- PRODUCTION COST ESTIMATES USED IN THIS STUDY

Method of Extraction	Name of Estimate	Source of Estimates	Study Code #
Underground Extraction Plus Surface Retorting	Tosco II	The Oil Shale Corp., Craun & Co., others	1A
	NPC - Audit Mine	National Petroleum Council, Union Oil others	1B
	NPC - Shaft Mine	National Petroleum Council, Union Oil, others	1C
	BOM - 100K U 50 G/T	Bureau of Mines, Morgantown	1D
	BOM - 50K U 30 G/T	Bureau of Mines, Morgantown	1E
	SRI - Lurgi	Stanford Research Institute	1F
	Hittman - U	Hittman Assoc., consultants	1G
Surface Extraction Plus Surface Retorting	NPC - open pit	National Petroleum Council, Union Oil, others	2A
	NPC - Strip	National Petroleum Council, Union Oil, others	2B
	BOM - 100K - S	Bureau of Mines, Morgantown	2C
	Hittman - U	Hittman Assoc., consultants	2D
Conventional	LLL - Block - C	Lawrence Livermore Lab & consultants	3A
	LLL - Stoping	Lawrence Livermore Lab & consultants	3B
	LLL - Caving - C	Lawrence Livermore Lab & consultants	3C
	BOM - 15GT-C 35K	Bureau of Mines, Morgantown	3D
	BOM - 22GT - C 35K	Bureau of Mines, Morgantown	3E
	BOM - 22GT - C 50K	Bureau of Mines, Morgantown	3F
Nuclear In Situ	LLL - W	Lawrence Livermore Lab	4A

Source: Rattien and Eaton, 1976.

Table 9 -- Production Costs of Raw Oil Shale

Process	Costs Expressed in 1974 Dollars	Costs Expressed in 1978 Dollars
Underground Mining and Surface Retorting		
Tosco - 1A [a/]	$ 5.21	$ 9.57
NPC - 1B	4.49	8.65
NPC - 1C	4.67	8.90
BOM - 1D	3.88	7.23
BOM - 1E	4.25	7.71
SRI - 1F	3.31	6.18
Hittman-1G	5.07	10.27
Surface Mining and Retorting		
NPC -2A	$ 4.91	$ 9.25
NPC -2B	4.48	8.64
BOM -2C	3.41	6.70
Hittman-2D	4.79	9.80
Convention In Situ		
LLL -3A	$ 5.92	$10.59
LLL -3B	6.74	11.99
LLL -3C	7.80	13.76
BOM -3D	8.74	15.65
BOM -3E	7.44	13.15
BOM -3F	9.55	16.73

Source: Rattien and Eaton, 1976.

a/ Abbreviations are taken from table 8.

Production costs for surface mining plus surface retorting were estimated to lie between $6.60 and $9.80 in 1978 dollars. Again, government estimate costs were lower than those of the National Petroleum Council, which represents the opinion of the oil industry. Estimates of costs for conventional and modified in-situ systems range from $10.59 to $16.73 per barrel in 1978 dollars. All of these estimates were made by government related groups. Rattien and Eaton state that to properly assess these figures one should realize that 1974 dollar costs greatly underestimate probable costs. This underestimation arises because the time when a plant will be built and operated will determine its actual cost and not those stated in terms of 1974 dollars. A shale plant built in 1979 through 1980 will have costs much greater than a plant which would be started in 1974. More recent technological development for the in-situ and modified in-situ systems have led industry representatives to believe that these are now the lowest cost methods of shale oil recovery.

There are other factors influencing the cost in the long run. Domestic taxes, shale land leasing and royalty policies will greatly affect profitability. But more important, the price of world petroleum may now be $13.00 per barrel, but will it stay there? Will world petroleum prices inflate with nominal dollar inflation or increase faster or slower than that? Further, Rattien and Eaton believe the costs in table 9 are likely to be optimistic, reflecting a base case of a 15 year facility lifetime and an 85 percent plant load factor. Shale oil costs are likely to be quite sensitive to these technical assumptions. Studies have found that operating and maintenance costs per barrel are 8 times higher with pessimistic assumptions (10 year lifetime and 50 percent down time) than with optimistic assumptions (30 year lifetime and 100 percent load factor). Overall costs per barrel were 3 times higher for the pessimistic case versus the optimistic case.

Table 10 is included to show how estimates of capital costs have risen in the recent past. For a single operating plant the estimates of cost more than tripled from 1972 to 1975. Some of the more important problems associated with commercialization of oil shale are the rather devastating inflation experienced in the recent past, the sharp increase in capital requirements, and the rather large uncertainties regarding retort and mining technology required for oil shale recovery. A commercial oil shale installation will consist of very large and complex units of mining and retorting and upgrading which have heretofore not been experienced. A high operational risk is involved since each operating

Table 10. History of Cost Estimates, Colony Shale Oil Plant

Date of Estimate	Initial Capital (millions of dollars)	Direct Operating Costs (dollars per barrel)	Oil Price for 10% ROR* (dollars per barrel)
1972 a/	225	1.82	4.40
March 1974 a/	425	3.13	8.00
August 1974 a/	653	4.30	11.50
September 1975 b/	960	3.26	14.20

* Rate of return; assumes 100% equity.

Source: Morse, 1976. a/ 50,000 bpd. b/ 55,000 bpd

unit must have a high availability, or "on-stream" factor to maintain the desired production levels. Failure to achieve this availability in any part of the system would have a disastrous effect on project economic viability. There is also a great deal of uncertainty and risk relative to environmental and political issues. The measures of costs associated with providing an environmentally acceptable facility are difficult to predict at present.

On the political side, the area of greatest uncertainty is whether product prices may be subject to some form of control while increasing expenses are not.

To this point we have described costs only for conventional methods of extracting oil from shale. There have been various discussions in the past regarding the possibility of nuclear in-situ retorting of shale. Some estimates of nuclear in-situ retorting have been made by the Lawrence Livermore Laboratory in California and reported by Rattien and Eaton (1976). While the economics are attractive, there are a number of crucial uncertainties. For example, one base case used was a column of rubble 2,000 feet high and an oil yield of 60 percent of Fischer Assay. Forming such a large retortable column is a difficult task and achieving a 60 percent Fischer Assay under these circumstances seems highly optimistic. The results of this study show that costs are very sensitive to modifications and technical assumptions. In 1978 dollars, the optimistic cost of $4.72 per barrel was achieved. Costs rose dramatically with smaller chimneys and lower yields.

The most recent estimates of the modified in-situ process are provided by Fenix and Scisson (1976). They considered two mining methods for the modified in-situ process: room and pillar mining and tunnel boring. The summary of input data for the economic evaluation of these two cases is provided in table 11. The evaluation was performed for a shale oil grade of 20 gallons per ton. The unrefined shale oil from the in-situ retorting process was assumed to be sold at the plant site. The relation of the discounted cash flow return on investments and cost per barrel for various selling prices of shale oil for each of the mining methods is shown in figure 12. In this case, cost per barrel is defined as the sum of annual operating costs, depreciation, federal depletion allowance, royalty, federal taxes, state and local taxes, and interest costs.

Depletion allowance and state and federal taxes are a function of product selling price; therefore, the costs per barrel increases with increasing selling price. (Selling prices were assumed to be $8, $11, $17, and $20 per barrel.) Figure 12 shows the relationship of the discount cash flow return on investment and selling price for each of the methods. The room and pillar mining method shows a cost advantage over the tunnel boring mining method. The lowest return on investment was 15 percent at $8 per barrel for the room and pillar method and ranged upward to 40 percent at $20 per barrel.

Morse (1976) provides some additional insights into the financial problems of oilshale development. Considering that capital investments for a 50,000 barrel per day underground mining oil shale complex are on the order of $1 billion, significant external financing will probably be required. Two factors affect the lenders' willingness to provide capital. They are the estimated rate of return on investment and the capital exposure or risk involved. The rate of return is quite sensitive to the profitability of the project and its expectation will affect the amount of capital the investor is willing to provide. Capital exposure, the amount of capital the lender stands to lose, is sensitive to how much certainty is associated with the pay-back of the capital invested. The Synfuels Interagency Task Force (1975) determined that the problem of capital availability and capital exposure are more significant to the smaller firms and independent ventures involving several firms. Consequently, the Task Force analyzed several incentives calculated to remove constraints to investment in shale oil venture. These include price guaranties, tax credits, loan guaranties, construction subsidies, and government plant ownership.

It was determined that price guaranties do help insure profitability and enhance capital availability because of the guaranteed rate of return. However, they do not reduce the capital exposure. Additionally, the recent oil price

Table 11-- Summary of Input Data for Economic Evaluations of Selected Cases for Modified In-Situ Mining.

Item	Room & Pillar Case	Tunnel Boring Case
Preproduction Period (years)	4	3
Capital Investment ($)	217,169,788	238,841,149
Replacement Capital ($)	138,609,240	158,296,988
Initial Mine Development ($)	66,698,185	32,061,713
Working Capital ($)	22,544,952	39,651,970
Royalty ($/Ton)	.12	.12
Annual Operating Cost ($)	5.55	9.72
Annual Interest Cost ($)	17,405,582	17,449,069
Number of Hourly Employees	2,928	3,390
Environment Impact Statement ($)	2,000,000	2,000,000
Predevelopment Engineering ($)	11,061,910	12,177,072
Mine Life (years)	17	30

The following factors are constant for both cases:

- Daily production: 50,000 BPD
- Operating days per year: 365.
- Processing recovery: 60% of Fischer assay
- Grade: 20 gpt.
- Federal tax rate: 50%
- Federal depletion rate: 15%.
- County mill levy: 40.
- Minimum royalty: $10,000.

Source: Fenix and Scisson, 1976.

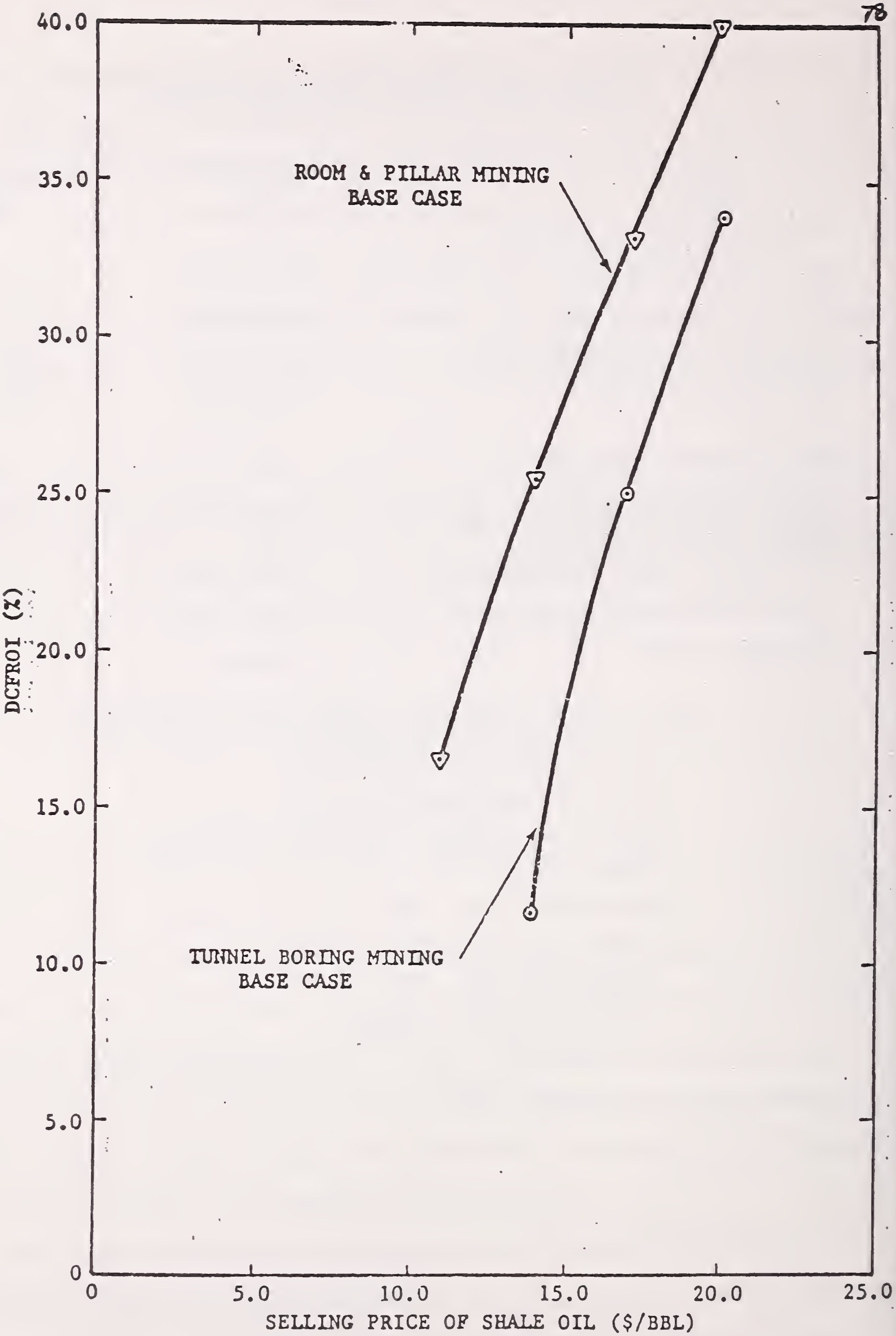


Figure 12-- DCFROI vs Selling Price of Shale Oil for Two Mining Systems

control legislation enacted by the Congress indicates that price guaranties are politically undesirable, except perhaps in the interest of national defense.

It was found that tax credits do not by themselves insure profitability. However, they will increase profits and accelerate the return on capital once an operation attains a profitable level, thus reducing capital exposure through a more rapid recapture of capital.

A federal loan guaranty program would provide an incentive to invest in a commercial shale oil industry and is probably the best means by which to encourage participation of smaller companies. A loan guaranty will probably have to be non-recourse, that is, if the participants default on the project they lose the investment capital they put into it, but the federal government is liable for the loan money that private lenders have put into the project. Hoskins et al. (1976) estimate that a 75 percent loan with a 9 percent interest rate would reduce the syncrude cost by $4.40 per barrel relative to a 100 percent equity case, assuming a 10 percent discounted cash flow rate of return.

The incentive of construction subsidy and government plant ownership effectively remove the problems of capital availability and capital exposure from the private sector. Unfortunately, these incentives also largely remove private enterprise from the shale oil arena.

The Water Resource

Introduction

Other than the direct and obvious effects of energy development on agriculture through competition for land use, water will provide the greatest degree of interaction and conflict between these activities. Because of such potential conflicts this section is devoted to an analysis of the facts, controversies and uncertainties surrounding water supplies in the oil shale area.

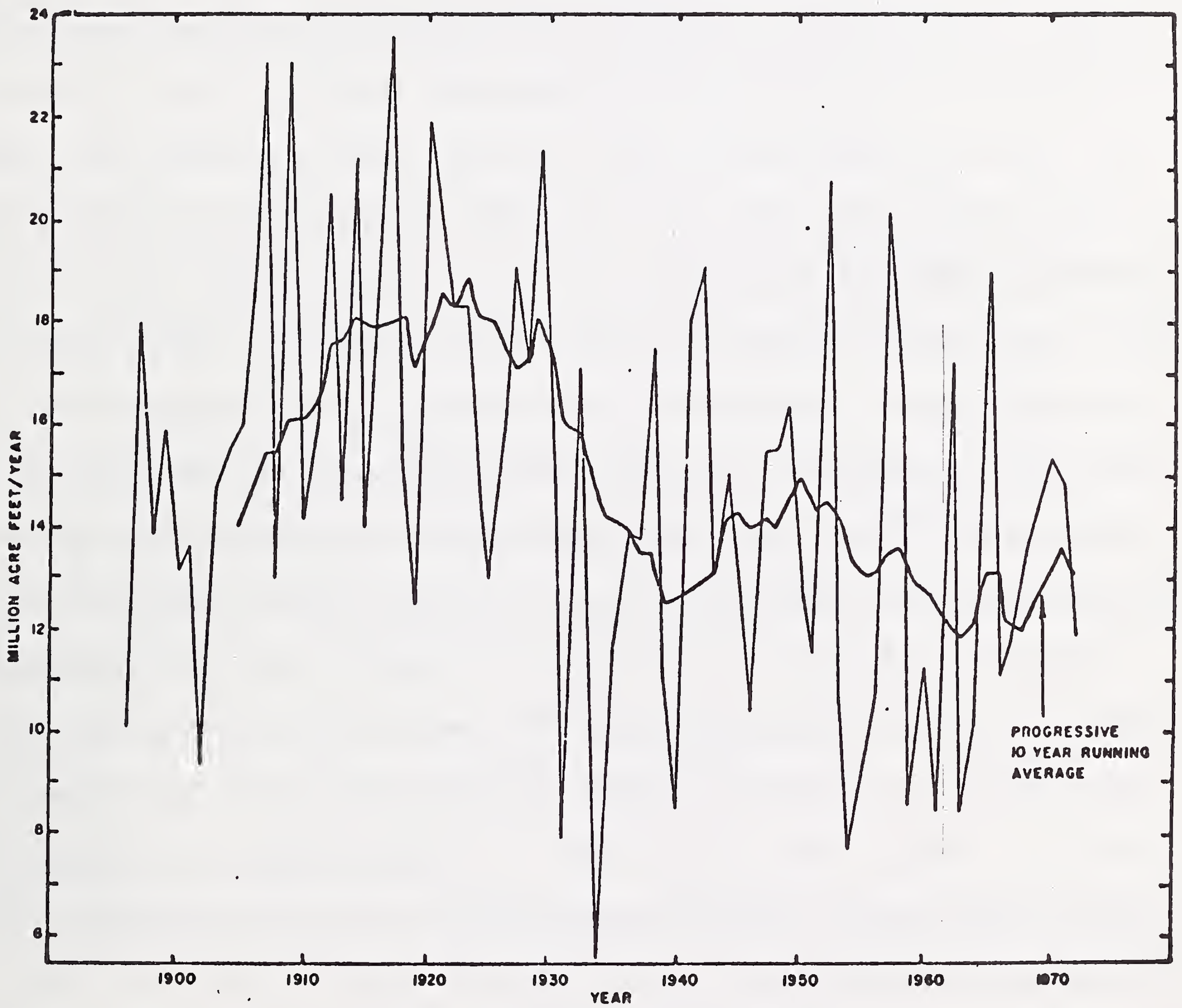
It has been established that the commonly described resources of U.S. oil shale lie in the Upper Colorado River Basin of Colorado, Utah, and Wyoming. Therefore, the analysis of water supply and demand problems will be restricted to this Basin.

The Setting

To estimate water availability for oil shale development there must be an initial determination of the aggregate supply to be allocated among competing uses. How much water is there in the Colorado River Basin and, more specifically, in the Upper Colorado River Basin? The fact is that supplies vary widely from one time frame to another. Figure 13 shows estimates of annual flow at Lee Ferry. The ten year average flow at this point has ranged from 18.5 million acre feet (1914-1923) to 11.6 million acre feet (1954-1963) (Andrews et al. 1975).

Unfortunately, the allocation of water between Upper Basin states (Utah, Colorado, Wyoming and New Mexico) and lower basin states (Arizona, California, and Nevada) as determined by the Colorado River Compact of 1922 was based upon pre-1920 river flow data (Gardner, et al., 1976). The Compact established the flow of the river available for distribution between upper and lower basin states at 15 million acre feet (maf) per year. This compact is considered to be the cornerstone of the body of law regulating the Colorado River. Its major

Figure 13. Colorado River—Average Annual Virgin Flow At Lee Ferry, Arizona



Source: Andrews, et al., 1975.

provision is one requiring the upper basin states to deliver at least 75 maf to the lower basin states in any consecutive 10-year period.

The 1922 Compact did not, however, divide the remaining water among the upper basin states. This allocation was supposedly accomplished in 1948 by the Upper Colorado River Basin Compact.

To further complicate the matter the Mexican Water Treaty (Rio Grande, Colorado and Tijuana Treaty) of 1944 provides Mexico an annual quantity of 1.5 maf from any and all sources (USDI, 1974, 6). The treaty does not, however, explain whether this water will be derived from the upper or lower basin allotment or a combination of both.

Thus, the setting is described. The Colorado River Compact and the subsequent Upper Basin Compact are based upon a greatly overestimated river flow and the source of Mexican Treaty obligations are not well defined (Gardner, 1976). More recent estimates have shown that the river's total yield is closer to 13.5 maf per year than the original 15 maf. The root cause of many present concerns is that the 1922 Compact and the Mexican Treaty have divided up more water than the river produces (Fischer, Aug. 1974). Additionally, the Mexican Treaty has more recently resulted in increased controversy because it has now been interpreted to include water quality which is not mentioned in the original treaty. As an interim measure, additional releases are being made to Mexico to dilute salinity concentrations.

To further complicate the matter the U.S. Supreme Court in 1908, in what has become known as the Winters Doctrine, held that when Indian reservations were established, sufficient water to supply all Indian lands was also reserved (Gardner, 1976). This decision has made the Indians holding land within the Colorado River Basin an important element in any plans to develop remaining or unused water. The essential point of the Winters decision is that water rights

set aside for Indian reservations are superior to other subsequent appropriators who obtained their rights under state law, even though the Indians have not yet put their rights to beneficial use (Hansen, 1975 as taken from Gardner 1976).

One major problem with rights defined under the Winters Doctrine is quantifying the Indian rights. If all irrigable lands belonging to the Indians were to be assessed as usable, the water rights would more than exhaust the remaining supplies in Utah (Gardner, 1976) and adversely affect plans for further development in other basin states. At this point in time no one knows what the ultimate outcome of Indian water claims will be.

One further complicating factor in the water resources picture is the Federal Reserved Water Doctrine. This doctrine as now being interpreted by Federal courts provides for unquantified water rights for federal reserved lands (e.g., National Parks, National Forests, mineral and energy development). These water rights apparently supercede state water rights already in use. The result is to create some uncertainty regarding availability of water to the private sector of the economy (Hillhouse, 1968).

A brief description of the major institutional agreements among Colorado River Basin water users follows (Andrews, et al., 1975):

The Colorado River Compact, 1922

The Colorado River Compact was concluded in 1922. It essentially divided the river in half at Lee Ferry, Arizona. The key provisions are in Article III: Section (a) apportioned to the upper and lower basins, respectively, "the exclusive beneficial consumptive use of 7,500,000 acre-feet of water per annum. . ." Section (d) provided that the Upper Basin states must insure that the flow of the river at Lee Ferry is not depleted below an aggregate of 75 million acre-feet for any period of 10 consecutive years.

The compact of 1922 has been the subject of wide disagreement and debate

mainly because of the provision that specifies a static quantity of water is to be delivered to the lower basin states. Studies undertaken to determine the flow of the Colorado for purposes of the compact estimated that the long-term annual virgin flow of the Colorado River at Lee Ferry was in excess of 18 million acre-feet based on the 1909-1920 period of record. The estimated annual virgin flow of the river has declined markedly since 1920. The amount of water allocated to the upper basin states decreases with each new estimate of annual virgin flow, whereas the lower basin states' allocation remains the same.

Boulder Canyon Act, 1928

This legislation, which authorized the construction of Hoover Dam and the All-American canal, also contained a provision stating that the project would be built only if California would agree irrevocably to limit its consumptive use to 4.4 million acre-feet (45 U.S.C. 1058, sec. 4), to which California acceded. The Act also authorized agreement on the suggested basis of 4.4 million acre-feet to California, 2.8 million acre-feet to Arizona, and 0.3 million acre-feet to Nevada. Although the states never agreed upon a compact, the 1963 Supreme Court decision, Arizona v. California, et al. (377 U.S. 546, 83 Sup. Ct. 1968, 10L. Ed. 2n 542, 1963) which affected the apportionment, adopted the suggestions of the Boulder Canyon Act. The Act also authorized the Secretary of the Interior to make investigations and publish reports on the feasibility of projects for irrigation, power, and other purposes in the basin. In 1946 a final report, The Colorado River, provided a comprehensive review of 132 potential projects for the Colorado River (HD 418, 80th Congress, 1st Session, 1947).

Upper Colorado River Basin Compact, 1948

The report, The Colorado River, provided a basis for compact negotiations among the upper basin states which resulted in the Upper Colorado River Basin Compact, 1948. The drafters of the compact recognized the problems of the 1922

compact and allocated water on a percentage basis. The scheme agreed upon allocated 50,000 acre-feet per year to Arizona, which has only a small part of the Upper Basin within its borders. The remainder was divided as follows: to Colorado, 51.75% of total beneficial consumptive use; New Mexico, 11.25%, Utah, 23%, and Wyoming, 14%. Congress consented to the compact in 1949.

The 1948 compact also set forth the principles by which the Upper Basin must curtail its consumption in the event a "compact call" is made under Article III (d) of the 1922 compact. An issue which the 1948 compact fails to address fully deals with those tributaries of the Colorado which leave the State of Colorado before their confluence with the main stem. Most of these rivers, such as the San Juan and Yampa, are the subject of interstate compacts of their own which are incorporated into the Upper Basin Compact. Of major importance to the oil shale industry, however, is the White River, which is unregulated by any interstate agreement. For a more detailed treatment of the compact call process and the problem of interstate allocation of the White River, see Appendix D of Andrews, et al., 1975.

The Upper Colorado River Storage Project Act, 1956

With the conclusion of the 1948 compact allocating water among the upper basin states, the way was clear for the Federal government to become involved in large-scale development of the Upper Basin. The Upper Colorado River Storage Project Act, passed by Congress in 1956 (70 U.S.C. 105) adopted the major features of an earlier Bureau of Reclamation study and authorized construction of 4 large storage reservoirs (Lake Powell, Flaming Gorge, Blue Mesa, and Navajo) and 11 reclamation projects. With the completion of the large reservoirs, which provide a combined storage capacity of over 24 million acre-feet, the flow at Lee Ferry can now be regulated and flood waters that previously flowed to the lower basin states can be captured for use in the Upper Basin. In addi-

tion, 9 of the 11 reclamation projects have been completed, and an additional 10 projects were authorized for construction under provisions of the act in 1962 (76 U.S.C. 96), 1964 (70 U.S.C. 852), and 1968 (82 U.S.C. 835).

Mexico Treaty, 1945

In 1945, as part of a treaty dealing with the Rio Grande, Tijuana, and Colorado rivers, the United States guaranteed to Mexico 1.5 million acre-feet annually from the Colorado, to be increased in years of surplus to 1.7 million acre-feet and to be reduced in years of extraordinary drought in proportion to the reduction of consumptive use in the U.S. (Mexican Treaty on Rio Grande, Colorado, and Tijuana Rivers, U.S.C. 994.59 stat. 1219, 1944 ratified by U.S. Senate April 18, 1945, effective November 8, 1945). For many years the upper basin states maintained that the obligation to Mexico was the responsibility of the Federal government, not the states. The Federal government acknowledged this obligation in the Colorado River Basin Project Act, 1968 (82 U.S.C. 995, sec. 202).

Even with the 1945 treaty, however, the problem of water quality remained. As consumptive use in the U.S. increased, the quality of the water delivered to Mexico decreased. After 1960, the water reaching Mexico was too saline for irrigation of most crops. In 1973, in Minute 242 of the International Boundary and Water Commission, the United States agreed to deliver water of a specified quality to Mexico. (Minute 242 of the International Boundary and Water Commission, August 30, 1973, T.I.A.'s 7708.) Minute No. 242 of the International Boundary and Water Commission requires that waters delivered to Mexico shall have an annual average salinity of no more than 115 ppm ± 30 ppm above the annual average salinity of Colorado River waters which arrive at Imperial Dam. Thus, the salinity standard is relative, not absolute. Our agreement with Mexico allows for continued increase in salinity of waters delivered across the border,

which means that Minute No. 242 may not be the "permanent and definitive solution" it is titled to be.

Minute 242 thrust the quasi-equilibrium of the river into some confusion. No mechanisms exist for regulating water quality; no standards for allocation of allowable degradation among states have been agreed upon. The obligation to maintain water quality, whether state or federal, poses special problems for the upper basin states. A large percentage of the river's salt load induced by human activities is caused by irrigation return flows in the Upper Basin. The states of the Upper Basin fear that any mechanisms adopted to control salinity will prevent these states from developing their share of the waters of the Colorado. The issue is unresolved at present, though the EPA, with authority granted by 1972 Water Quality Amendments (PL 92-500), is preparing standards for reducing salinity of the river.

Surface Water Supplies

The major problem created by the various institutional arrangements regulating the Colorado River is a resulting disagreement regarding how much water there is to be divided among users. The consequence has been that each state has chosen to interpret the potential outcome to favor its position and has proceeded to plan water development on that basis. The potential conflicts will most likely have to be resolved in the courts.

To better understand the situation, the allocation of water to all lower basin states averaged 7.5 maf per year by the 1922 compact. The Lower Basin states and the Federal government also favor the position which requires the upper basin states to provide one-half of the Mexican allocation or 0.75 maf per year. This interpretation requires the upper basin states to release an average of 8.25 maf per year to the lower basin as measured at Lee Ferry. Actually, more than this amount would have to be supplied to offset reservoir

evaporation and channel seepage losses below Lee Ferry. Probably something like 9.0 mafy would be needed.

The original division of upper and lower basin allocations was based upon an assumed 10 year average annual flow exceeding 18 maf. As late as 1974 some agencies were using an assumed flow of 15 maf to estimate water supplies in the Colorado River Basin (USDI, 1974, b). The U.S. Bureau of Reclamation has analyzed water problems in the 11 western states using estimates ranging from 13.2 maf to 15.5 maf with a compromise value of 14.1 maf being given most probable status (USBR, 1975). Andrews, et al. (1975) cites the Bureau of Reclamation as favoring a figure of 13.8 maf. The Lake Powell Research Group settled on a range in water yield of 13.0 - 13.5 maf and this range was adopted by Andrews, et al. (1975). Finally, nature provided an average runoff of only 11.6 maf for the period 1954-63. Thus, the boundaries are drawn. It also becomes obvious how easily states can arrive at differing estimates of their own water allocations. Table 12 provides a rough breakdown of water allocation to upper basin states based upon some alternative assessments of gross river flows. In this table it is presumed that Lower Basin states and Mexico will always be entitled to an allocation of 8.25 maf regardless of the yield of the river. Also, Arizona is guaranteed an annual flow of 50,000 acre-feet from the Upper Basin states allotment. While the 1922 compact and subsequent federal interpretations tend to support this view, it is not clear that Upper Basin states will be so inclined, particularly if actual flows fall substantially below the 15 maf level. It is not within the scope of this report to even describe the legal and institutional problems that may arise in its resolution.

Table 12 shows that Colorado claims on the Colorado River could range from 1.71-5.02 maf. Similar variability could be applied to Utah and Wyoming water allocations.

Table 12 -- Estimated allocation of Colorado River water to oil shale states based upon alternative gross annual river flows - maf

Annual flow	Lower Basin and Arizona	Colorado	Utah	Wyoming
18.00	8.30	5.02	2.23	1.36
15.50	8.30	3.73	1.66	1.01
14.00	8.30	2.98	1.32	0.80
13.30	8.30	2.59	1.15	0.70
11.60	8.30	1.71	0.76	0.46

Table 13 shows a breakdown of water use among the oil shale states and provides an estimate of the amount of water that could be allocated to oil shale development (USDI, 1974). The figures shown in this table are based upon an assumed Upper Basin allocation of 5.75 maf or a gross flow of about 14.0 maf if the Lower Basin states and Mexico are given 8.25 maf. This set of figures, developed by the Department of Interior, shows Colorado with 90,000 acre-feet of water that could be devoted to oil shale production. Utah and Wyoming have even larger supplies of water for this use. However, it is important to note that commitments for future water use in Colorado already exceed potential supplies by 64,000 acre-feet, implying that some future commitments or current uses will have to be reduced to supply any water to oil shale development. Of course, this estimate is based on an assumed Colorado share of 2.976 maf of water. According to table 12 the most probable supply of water for Colorado would be 2.59 maf if current estimates of total flow equaling 13.3 maf are accurate. The difference in Colorado is more than 300,000 acre feet and could cut severely into its future water use plans. Note also that Utah has a reduction of about 160,000 acre feet of water if the lower estimate of Colorado River flow is accepted.

To illustrate the potential confusion created by these figures we can observe recent claims of water supply in Utah and Colorado. The state of Utah

Table 13-- Present and Future Water Use in the Upper Colorado River Basin (Thousand acre-feet per year)

	Colorado	Utah	Wyoming	Total
State share of 5,750,000 acre-feet 1/............	2,976	1,322	805	5,103
1974 Use..................	-1,855	- 705	-328	-2,888
Committed Future Use.......	- 916	- 381	-371	-1,668
Evaporation from Storage Units....................	- 269	- 120	- 73	- 462
Not Identified as to Use...	- 64	116	33	85
Committed future use that could be made available for oil shale...........	154 2/	12 3/	200 4/	366
Total potential water that could be made available for depletion for development 5/	90 6/	128	233	451

1/ Arizona received the right to the consumptive use of 50,000 acre-feet per year.

2/ From the existing Green Mountain and Ruedi Reservoirs and the authorized West Divide Project.

3/ From the authorized Jensen, Upalco, and Uintah Units.

4/ From the existing Fontenelle Reservoir - Seedskadee Project.

5/ This includes water not presently identified for a particular use, plus water from authorized projects committed to oil shale development and water from existing reservoirs not presently committed to a particular use. Additional water can be made available if the States permit the industry to purchase some of the water rights from those presently using water and if the use category is changed from some of the future commitments.

6/ The water committed to future use that could be made available to oil shale (154,000 A/F) would be reduced to 90,000 A/F only if apparent over commitment of 64,000 A/F is removed from those committed uses that could provide water for oil shale. It is possible that other committed future uses will not develop as indicated or that a higher priority may be given to oil shale development. In that event, it would be possible that additional water could be made available for oil shale or other industrial uses.

Source: USDI, 1974b.

generally takes a liberal view of its claim on Colorado River water placing it at 1.4 maf (Gardner, et al., 1976), compared to a potential value of 1.15 maf as shown in table 12. This same source claims the unused portion of Utah's share to be 600,000 acre feet. Felix L. Sparks (1974), Director of the Colorado Water Conservation Board, describes an environmental impact statement on the potential Colony Development as being "too low" when saying that there are only 160,000 acre-feet of uncommitted water available for oil shale development. He says there are at least 800,000 acre-feet of water available to Colorado on an annual basis which is not now being used and at least 250,000 acre-feet could be made available to oil shale development. Sparks believes this to be "true under the most restrictive interpretations of the available allocations under the interstate compacts and Mexican water treaty."

In both Colorado and Utah there are conditional water decrees awarding the use of water which exceed even the state's estimates of current surpluses. However, this water has not yet been put to beneficial use and, therefore, could be devoted to energy development. There are, for example, seven authorized Bureau of Reclamation projects in Western Colorado which have not yet been constructed. The total depletion of these seven projects is estimated at 450,000 acre-feet (Sparks, 1974). Some of the water in these projects is planned for energy development, however.

Glenn (1976) provides a more complete accounting of water use in the upper basin states. His estimates of current consumption taken from USDI, 1974, are shown in table 14. Glenn properly charges the upper basin states with their share of main stem reservoir losses. These evaporation losses amount to 269,000 acre feet for Colorado and 120,000 acre-feet for Utah. Glenn used estimated water requirements for planned energy projects

Table 14--Estimated 1974 Upper Colorado River Basin Depletions 1,000 Acre-Feet

	Colorado	Utah	Wyoming
Thermal Powerplants	9	1	3
Food and Fiber (Irrigation)	1,255	529	258
Fish, Wildlife, and Recreation 1/	31	24	16
Minerals and Mining	17	9	18
Livestock Ponds and Evaporation	21	6	2/ 21
Municipal and Industrial	18	6	3
Exports	504	130	10
Coal - Gasification			
Oil Shale			
Subtotal	1,855	705	328
Main Stem Reservoir Losses	269	120	73
Total Depletion	2,124	825	401

1/ Natural historic wildlife consumption not included.

2/ Includes evaporation from Fontenelle Reservoir.

Source: Glenn, 1976.

(Coal fired electric generating plant-15 acre-feet/year/mw at 85 percent plant factor;

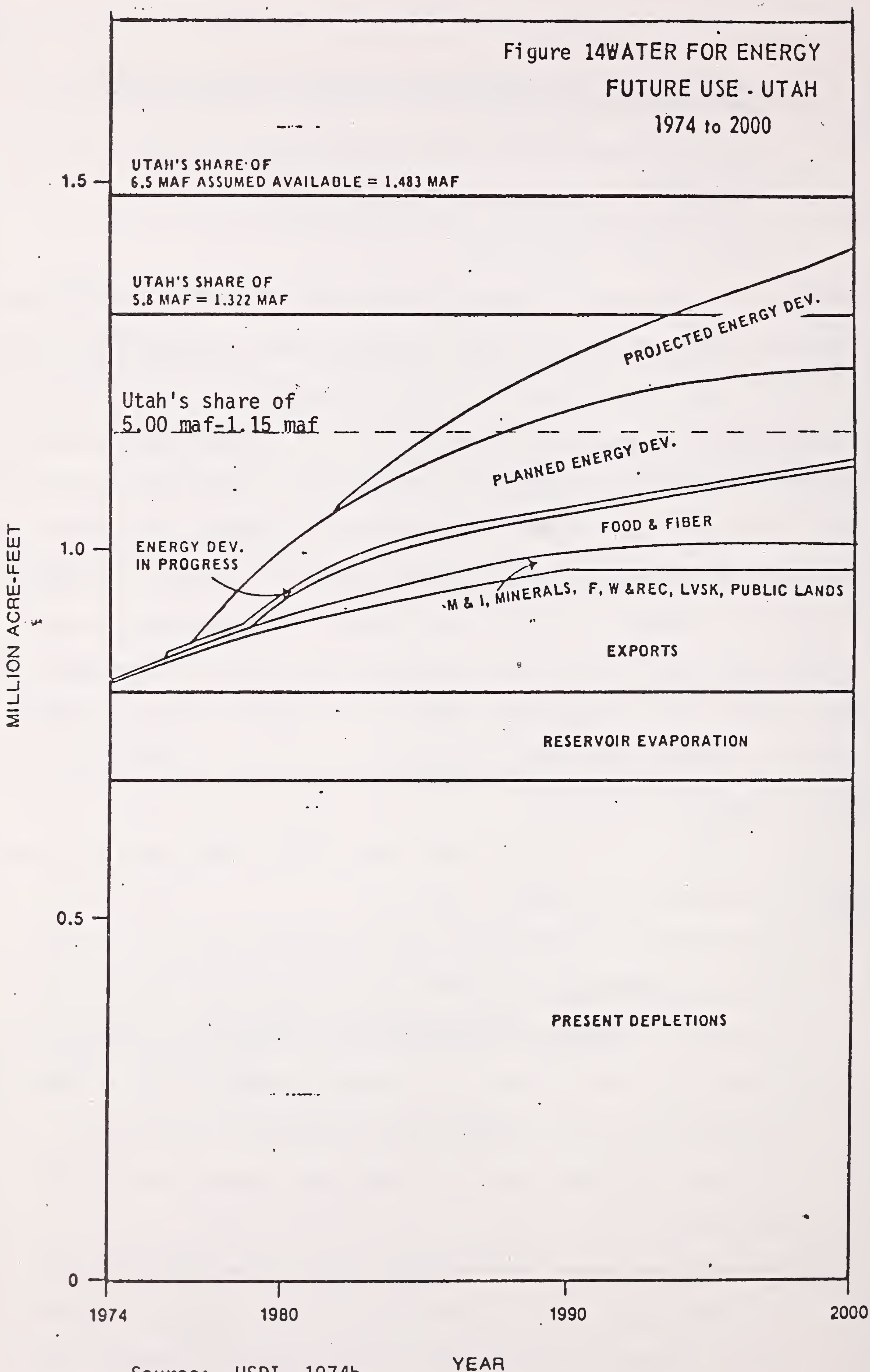
Oil shale-17,400 acre-feet per year for 100,000 bbl/day plant; and,

Coal gasification plant-15,000 acre-feet per year for 250 million cubic feet per day)

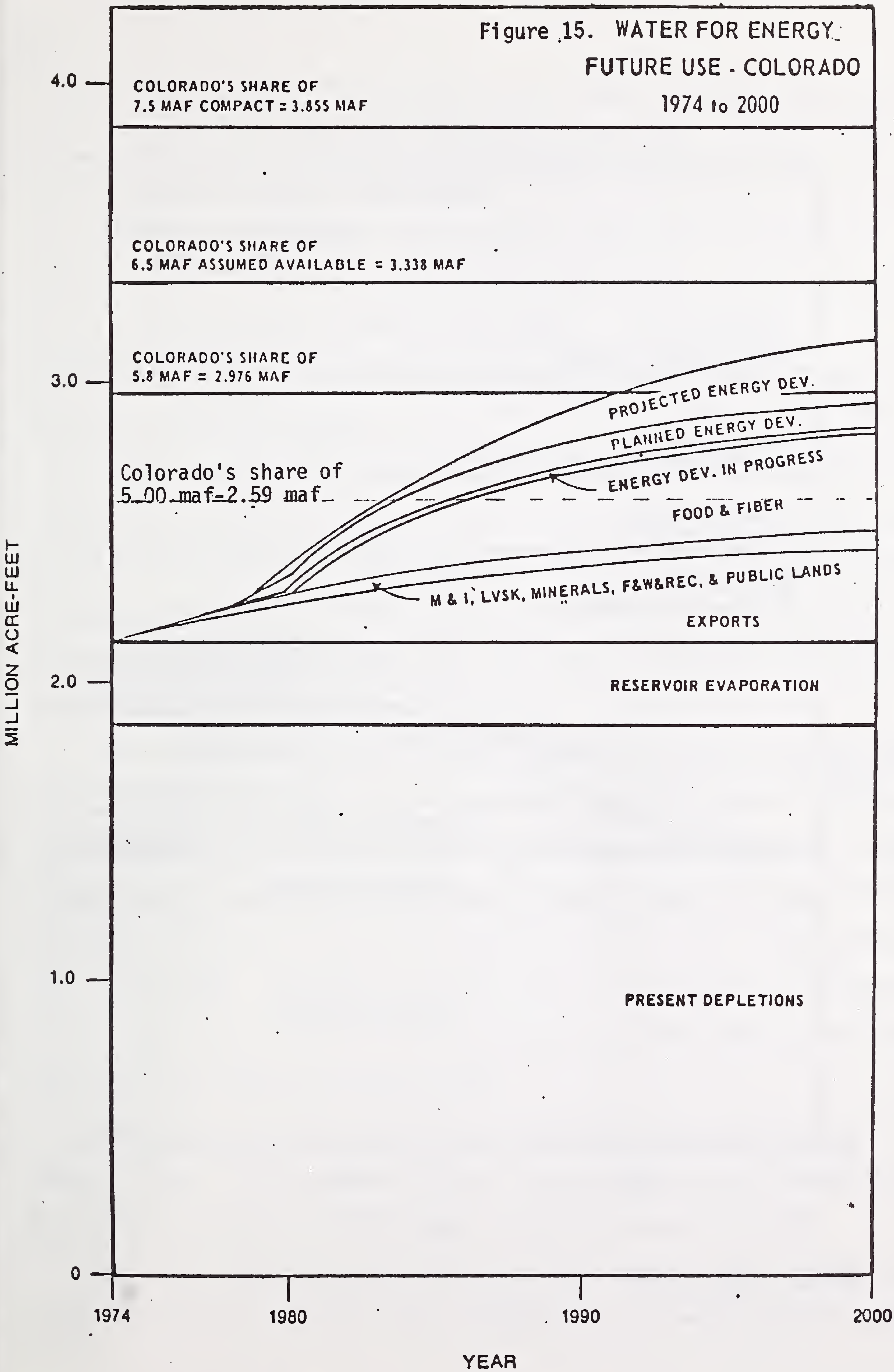
to estimate the future water demands for each state and compare them to some alternative supply conditions. These estimates, shown in figures 14, 15, and 16 for Colorado, Utah and Wyoming respectively, were made at the time the federal oil shale lease tracts were still considered viable for development. Since then, their development has come to a complete halt and then partially revived under alternative technologies with differing water demands. Also the estimates of water use by agriculture include several authorized reclamation projects which are yet unfunded or only partially funded. President Carter recently suspended development on three such projects in Colorado and called for additional review of their feasibility. Thus, it is probable that many changes could occur to cause actual water consumption to deviate from the trajectories shown in figures 14, 15 and 16.

Glenn (1976, p. 19) lists some additional factors which could also affect current projections of water use. They are:

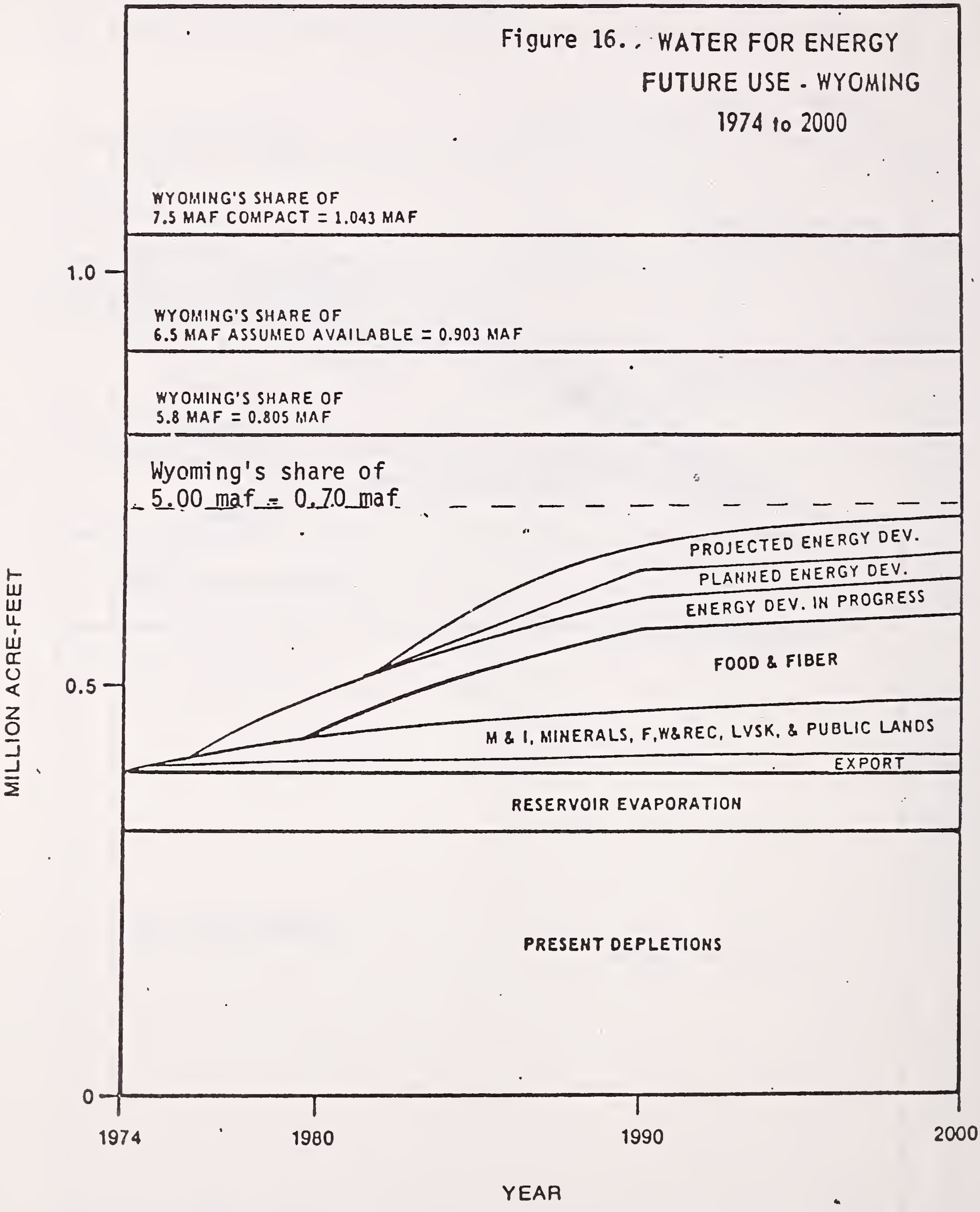
1. Air cooling in lieu of water cooling is being considered for some plant designs today. As water supplies become more expensive and difficult to obtain, air cooling may be utilized to an increasing degree. For those plants in a projected category, it would seem reasonable that half of them would be designed to utilize air cooling. This would result in a decreased demand of some 160,000 acre-feet.
2. Augmentation through weather modification in the Upper Basin can be accomplished. With implementation of such a program, a conservative increase in water supply by year 2000 of 500 thousand acre-feet is attainable.



Source: USDI, 1974b.



Source: USDI, 1974b.



Source: USDI, 1974b.

3. The purchasing of agricultural water rights by energy interests is occurring in some parts of the Upper Basin today. Although the extent of this activity is very difficult to determine, it is conservatively estimated that 5 percent (about 90,000 acre-feet) of current agricultural water supplies in Colorado and Utah will have been converted to energy by year 2000.

Each of these would have the effect of decreasing aggregate water demands or increasing potential supplies.

In any case, figure 14 shows Colorado to be approaching the limits of supply between 1990 and 2000 if the more liberal estimate of gross annual flows equaling 14.1 maf is used (table 12) providing 5.8 maf to the upper basin states. Using the conservative, but more recently accepted, estimate of river flow equaling 13.3 maf, Colorado will reach the limit of supply prior to 1990 if projected uses are consummated.

Figure 15 shows Utah to be in about the same position as Colorado regarding plans for future water use. Some slight deviations from current plans would allow development to year 2000 without an inhibiting water supply if it can be assumed that the upper basin states have 5.8 maf to share. Following Utah's assumption of having 1.4 maf to use there would be no limits on development until beyond 2000. Conversely, the more restrictive assumption of having 13.3 maf of water in the river providing the upper basin states only 5.0 maf would leave Utah in a deficit position by 1985.

Wyoming, as shown by figure 16, currently uses only a small portion of its water share. Because of more modest projections of future use, there appear to be no problems of water supply in Wyoming through year 2000.

Gray et al. (1977) recently calculated water supplies in the Rocky Mountain states that could be used for energy development. A summary of their results

is shown in table 15. It is apparent that their assessment of gross flows in the upper basin at 14.872 maf exceed most other recent estimates. Nevertheless, their estimates of current use in the Upper Basin states are in agreement with others cited herein. One notable feature of this table is the projection of use for Colorado River water. These projections are based on past water use trends and not any specific plans (energy, agriculture, municipal, etc.) for water use that may exist. In all cases these projected water use rates are below those estimated by Glenn (1976). None of the upper basin states would experience a water shortage through 2020 if the river yield is 14.872 maf as assumed by Gray, et al. If the river yield is as low as 13.3 maf Colorado and Utah would begin to experience shortages by 2020 but Wyoming would still be in a surplus condition.

An important factor in the figures of Gray et al. is the presumed residual outflow at Lee Ferry. While the Colorado River compact and the Mexican Treaty call for an average annual flow of 8.25 maf at this point, they show a potential flow of 9.186 maf through 2020. Even with this assumed excess flow, however, it is apparent that if Lower Basin states meet their water use goals the residual outflow of the river will be insufficient to meet the Mexican treaty requirements of 1.5 maf. In fact, Gray et al. do not show sufficient outflow to meet that requirement at this time. If current outflow at Lee Ferry were reduced by 2.92 maf to only meet treaty rights, the Lower Basin states would have to reduce current water consumption by 3.56 maf, possibly restrict growth plans or find alternative water sources. In any case, as Upper Basin development continues it is apparent that the Lower Basin states are going to very quickly be in a deficit water situation. Gray et al. recognize this possibility by stating that deficits in the Lower Basin states will be primarily financed through the mining of groundwater supplies.

Table 15

COLORADO RIVER BASIN SUMMARY

(1000 acre-feet per year)

	Present	1980	2000	2020
Upper Colorado Virgin Supply	14,872	14,872	14,872	14,872
Less: Arizona Depletions	25	50	50	50
Colorado Depletions	2,097	2,436	3,078	3,082
New Mexico Depletions	332	467	639	656
Utah Depletions	835	935	1,105	1,157
Wyoming Depletions	409	521	682	741
Residual Outflow (Lee Ferry)	11,174	10,463	9,318	9,186
Plus: Virgin Supply Originating in the Lower Colorado Basin	3,129	3,129	3,129	3,129
Lower Colorado Water Supply	14,303	13,592	12,447	12,315
Less: Arizona Depletions	5,417	6,240	5,850	6,434
Nevada Depletions	251	353	514	665
New Mexico Depletions	89	126	156	165
Utah Depletions	72	101	104	115
Main Stem Depletions	7,510	6,510	6,140	6,140
Residual Outflow (Mexico)	964	262	-317	-1,204

Source: Gray, et al., 1977.

By now it has become apparent that anyone expecting a definitive analysis of water available for energy development in Colorado, Utah and Wyoming is doomed to disappointment. Obviously there is insufficient water to meet all planned use in Colorado, and probably, in Utah through year 2000 or 2020. On the other hand, even the restrictive assumption of Colorado River flow of 13.3 maf as shown by

State	Water allocation	Current water use	Unused water
	maf		
Colorado	2.59	2.12	0.47
Utah	1.15	0.83	0.33
Wyoming	0.70	0.40	0.30

leaves each of the oil shale states with a current surplus of surface water supply. While there are more plans for this water in Colorado and Utah than can be supported, a very sizable energy industry could be developed without necessarily detracting from any current uses of water. Of course, there would need to be some reordering of priorities if energy development required diverting water from planned development of agricultural or municipal uses.

The upper Colorado River Basin surface water is overappropriated (Glenn, 1976). This is especially true in Colorado and Utah where water rights exceed not only present water use but also the long run potential water supply. Consequently, there is no meaningful way of reconciling individual appropriations or group appropriations with present water use figures. With the supply already overappropriated additional water users must obtain water rights out of existing established rights in most cases. The states need to begin comprehensive evaluations of existing water rights and establish priorities for the use of remaining water supplies.

Existing Rights

Many of the existing water rights in Colorado, Utah and Wyoming, though

currently unused, are held by industrial firms. Table 16 shows industrial water rights in Colorado that precede 1960. Many of the firms in this list are also involved in oil shale development and could make water available for this purpose if the rights were eventually upheld.

The Green Mountain Reservoir and Reudi Reservoir are already constructed and have some storage capacity that can be diverted to oil shale development. Based upon admittedly rough estimates, from 20,000 to as much as 90,000 acre-feet of water can be made available from these reservoirs for an oil shale industry (Andrews, et al. 1975). The Bureau of Reclamation currently holds rights to this water and could be persuaded to sell the water for this purpose. However, any contract negotiated with the Bureau would probably face litigation barriers. The outcome of such procedures cannot be predicted at this point. The Governor of Colorado has just recently reached an agreement with the Secretary of the Interior allowing the governor some say in protecting irrigation from BuRec water sales to industry.

A major determinant of water availability for oil shale development in Colorado is going to be the attitude of the people and officials in the state regarding this issue. Colorado, among the three oil shale states, seems to be taking a relatively conservative and cautious position in committing water for oil shale development. Agricultural, municipal and environmental uses of water are also given high priority in Colorado's development plans. Nevertheless, there is some water that could be made available for oil shale development in Colorado without detracting from any other present consumptive use. A pressing national need for oil shale development would undoubtedly bring forth the necessary water.

Utah has taken a more aggressive attitude toward oil shale, and other energy development. Certain portions of remaining surface supplies in the Upper Colo-

TABLE 16. INDUSTRIAL WATER RIGHTS WITH APPROPRIATION DATES PRIOR TO 1960

Structure	Appropriation Date	Decreed Right[1]
Green Mountain Reservoir	10/26/37	152,000[2,3] acre-feet
Union Pipeline	2/14/49	118 cfs from Colorado River
Citgo Pipeline	8/02/51	100 cfs from Colorado River
Draggert Pipeline (Chevron)	11/16/51	94 cfs from Colorado River
Getty Oil Company	11/19/51	56 cfs from Colorado River
Eaton Pipeline (Chevron)	11/21/51	100 cfs from Colorado River
Pacific Oil Pipeline (Chevron)	6/09/53	100 cfs from Colorado River
Pacific Oil Pipeline (Arco)	6/09/53	100 cfs from Colorado River
Bearwallow Reservoir	6/28/54	49,292 acre-feet
Dow Pipeline (Colony)	1/24/55	178 cfs from Colorado River
Exxon Reservoir and White Pipeline	5/29/55	10,744 and 70 cfs from White River
Dallas Creek	11/16/56	(37,000 acre-feet)
Sinclair Pipeline (Arco)	11/21/56	33 cfs from Colorado River
TOSCO Pipeline	12/03/56	100 cfs from Colorado River
West Divide Project	4/22/57	(76,000 acre-feet)
Reudi Reservoir	2/29/57	102,000 acre-feet
Yellow Jacket Project	12/11/57	(57,000 acre-feet)
Sweetwater Project	12/18/57	Note 4
Iron Mountain Reservoir	8/10/56	68,052 acre-feet
Lower Yampa Project	7/06/59	(84,000 acre-feet)
Elie Pipeline (Dodge Co.)	9/01/59	34 cfs from Colorado River
TOSCO Pipeline #2	10/07/59	100 cfs from Colorado River

[1] Numbers enclosed in parentheses refer to estimated annual consumptive use of water from project.

[2] The availability of water from Green Mountain and Reudi reservoirs for industrial uses is discussed in more detail in the text.

[3] Storage rights are expressed in acre-feet of storage permitted each year, direct diversion rights in cubic feet per second in accordance with standard conventions.

[4] The Sweetwater project is a very complex hydroelectric power project.

cfs = cubic feet per second
1 cfs-1.98 acre feet per day

Source: Andrews, et. al., 1975.

rado Basin are being definitely planned for energy use. The state has plans for constructing a dam at state expense on the White River which has the expressed purpose of supplying about 26,000 acre-feet per year of water for oil shale development. The dam will also expand irrigation on Ute Indian lands near the confluence of the Green and White Rivers (Bingham Engineering, 1976). More will be said about this factor when discussing the agricultural impacts of oil shale development.

In all cases, with the exception of Green Mountain and Reudi reservoirs in Colorado which already exist, water storage facilities will probably have to be built to supply additional surface water to any consumptive use in Colorado or Utah. The Bureau of Reclamation has assessed the major alternatives for storage and pipeline facilities that could provide water to Federal lease tracts Ca, Cb, Ua, and Ub (USBR, 1974). Tables 17, 18 and 19 summarize the results of the Bureau study for plans which appear to be most desirable. While these data are specific to supplying these lease tracts with water, they are quite typical of what could be expected for general development needs. Colorado tracts Ca and Cb could be supplied water at costs ranging generally in the $100-$180 per acre-foot category (1974 costs). Utah tracts Ua and Ub are more favorably situated to water supplies and could obtain water at costs generally below $100 per acre foot. The Lower White River project which is similar to the one being most seriously contemplated by the State of Utah would provide water at $33 per acre foot. Water costs several times this high would still not be prohibitive to oil shale development. If a 100,000 barrel per day underground mine with a surface retort would require 15,600 acre feet of water per year (table 5), a $200 per acre-foot of water the cost would be about $0.10 per barrel of oil. Modified in-situ methods of mining being considered today would use considerably less water per barrel of oil produced.

Table 17.

Summary of alternatives for supplying water to prototype oil shale development in Colorado (Tract C-a)

	Single-purpose developments			
	Pumping from Colorado River	Yellow Creek Reservoir	Ripple Reservoir	Pumping from Colorado River (Joint with C-b)
Source of water	Colorado River and Ruedi Reservoir	White River	White River	Colorado River and Ruedi Reservoir
Annual firm water supply (ac.-ft.) Industrial	57,000	57,000	57,000	57,000
Quality of water diverted				
Total dissolved solids - (mg/1)				
Average	500	270	320	500
Range	160-930		200-500	160-930
Capital costs				
Construction cost (Jan. 1974 prices)	$64,800,000	$54,900,000	$55,700,000	$55,970,000
Interest during construction	7,780,000	6,590,000	6,690,000	6,720,000
Total	72,580,000	61,490,000	62,390,000	62,690,000
Annual equivalent cost (6 percent, 40 years)	4,824,000	4,087,000	4,147,000	4,167,000
Annual operating costs				
Water purchase	1/$450,000	1/0	1/0	1/$450,000
Power	2,985,000	$1,691,000	$1,482,000	2,949,500
Operation, maintenance, and replacements	299,000	189,000	131,000	273,500
Total	3,734,000	1,880,000	1,613,000	3,673,000
Total annual costs				
Total	$8,558,000	$5,967,000	$5,760,000	$7,840,000
Per acre-foot of water supplied	150	105	101	138

1/ Does not include costs for purchase of senior water rights.

Table 17a.

Summary of alternatives for supplying water to prototype oil shale development in Colorado (Tract C-a)

	Multi-purpose developments					
	West Divide Project (Joint with C-b)	Lower Yampa Project (Joint with C-b)	Yellow Jacket Project (Joint with C-b)	Yellow Jacket Project (Joint with C-b, U-a, and U-b Pumping)	Yellow Jacket Project (Joint with C-b, U-a, and U-b--pumping and gravity	Yellow Jacket Project (Joint with C-b U-a, U-b—Gravity)
Source of water	Colorado River and Una Reservoir	Yampa River and Juniper Reservoir	White River and Ripple and Lost Park Reservoirs	White River and Ripple, Lost Park, and Powell Park Reservoirs	White River and Ripple, Lost Park, and Buford Reservoirs	White River and Ripple, Lost Park, and Buford Reservoirs
Annual firm water supply (ac.-ft.) Industrial	57,000	57,000	57,000	57,000	57,000	57,000
Quality of water diverted						
Total dissolved solids - (mg/1)						
Average	500	230	360	360	360	360
Range	160-930	150-500	200-600	200-600	200-600	200-600
Capital costs						
Construction cost (Jan. 1974 prices)	$97,740,000	$103,380,000	$55,700,000	$55,600,000	$71,131,000	$87,666,000
Interest during construction	11,730,000	12,410,000	6,690,000	6,680,000	8,540,000	10,520,000
Total	109,470,000	115,790,000	62,390,000	62,280,000	79,671,000	98,186,000
Annual equivalent cost (6 percent, 40 years)	7,275,000	7,695,000	4,147,000	4,140,000	5,295,000	6,526,000
Annual operating costs						
Water purchase	0	0	0	0	0	0
Power	$2,949,500	$2,304,700	$1,482,000	$1,482,000	$860,000	0
Operation, maintenance, and replacements	283,500	262,200	131,000	131,000	125,700	$125,000
Total	3,233,000	2,566,900	1,613,000	1,613,000	985,700	125,000
Total annual costs						
Total	$10,508,000	$10,261,900	$5,750,000	$5,753,000	$6,280,700	$6,651,000
Per acre-foot of water supplied	185	180	101	101	110	117

SOURCE: U.S. Bureau of Reclamation, 1974.

Table 18.

Summary of alternatives for supplying water to prototype oil shale development in Colorado (Tract C-b)

	Single-purpose developments		
	Pumping from Colorado River	Ripple Reservoir	Pumping from Colorado River (Joint with C-a)
Source of water	Colorado River	White River	Colorado River and Ruedi Reservoir
Annual firm water supply (ac.-ft.) Industrial	18,000	18,000	18,000
Quality of water diverted			
Total dissolved solids - (mg/1)			
Average	500	320	500
Range	160–930	200–500	160–930
Capital costs			
Construction cost (Jan. 1974 prices)	$19,900,000	$19,400,000	$13,130,000
Interest during construction	2,390,000	2,330,000	1,580,000
Total	22,290,000	21,730,000	14,710,000
Annual equivalent cost (6 percent, 40 years)	1,482,000	1,444,000	978,000
Annual operating costs			
Water purchase	1/ 0	1/ 0	1/ 0
Power	$783,000	$448,000	$857,500
Operation, maintenance, and replacements	181,000	134,000	89,500
Total	964,000	582,000	947,000
Total annual costs			
Total	$2,446,000	$2,026,000	$1,925,000
Per acre-foot of water supplied	136	113	107

1/ Does not include costs for purchase of senior water rights.

Table 18a Summary of alternatives for supplying water to prototype oil shale development in Colorado (Tract C-b)

	Multi-purpose developments					
	West Divide Project (Joint with C-a)	Lower Yampa Project (Joint with C-a)	Yellow Jacket Project (Joint with C-a)	Yellow Jacket Project (Joint with C-a, U-a, and U-b Pumping)	Yellow Jacket Project (Joint with C-a, U-a, and U-b—pumping and gravity	Yellow Jacket Project (Joint with C-a U-a, U-b—Gravity)
Source of water	Colorado River and Una Reservoir	Yampa River and Juniper Reservoir	White River and Ripple and Lost Park Reservoirs	White River and Ripple, Lost Park, and Powell Park Reservoirs	White River and Ripple, Lost Park, and Buford Reservoirs	White River and Ripple, Lost Park, and Buford Reservoirs
Annual firm water supply (ac.-ft.) Industrial	18,000	18,000	18,000	18,000	18,000	18,000
Quality of water diverted						
Total dissolved solids - (mg/l)						
Average	500	230	360	360	320	320
Range	160-930	150-500	200-600	200-500	200-500	200-500
Capital costs						
Construction cost (Jan. 1974 prices)	$30,860,000	$26,780,000	$18,140,000	$17,490,000	$16,634,000	$19,089,000
Interest during construction	3,710,000	3,220,000	2,180,000	2,100,000	2,000,000	2,300,000
Total	34,570,000	30,000,000	20,320,000	19,590,000	18,634,000	21,389,000
Annual equivalent cost (6 percent, 40 years)	2,300,000	1,994,000	1,351,000	1,302,000	1,239,000	1,422,000
Annual operating costs						
Water purchase	0	0	0	0	0	0
Power	$857,500	$520,000	$448,000	$448,000	$70,900	0
Operation, maintenance, and replacements	89,500	82,800	134,000	134,000	48,300	52,000.
Total	947,000	603,100	582,000	582,000	119,200	52,000
Total annual costs						
Total	$3,247,000	$2,597,100	$1,933,000	$1,884,000	$1,358,200	$1,474,000
Per acre-foot of water supplied	180	145	107	105	76	82

SOURCE: U.S. Bureau of Reclamation, 1974.

Table 19 Summary of alternatives for supplying water to prototype oil shale development in Utah (Tracts U-a and U-b)

	Single-purpose developments				
	Pumping from Green River near Ashley Creek	Pumping from Green River near Ouray, Utah	Tyzack Reservoir	Watson Reservoir	Hells Hole Canyon Reservoir (offstream)
Source of water	Flaming Gorge Reservoir	Starvation Reservoir	Authorized Tyzack Reservoir	White River	White River
Annual firm water supply (ac.-ft.)					
Industrial	18,000	18,000	0	18,000	18,000
Municipal	18,000	18,000	8,000	18,000	18,000
Total	36,000	36,000	8,000	36,000	36,000
Quality of water diverted					
Total dissolved solids - (mg/l)					
Average	430	450	150	550	500
Range	130-650	150-700			
Capital costs					
Construction cost (Jan. 1974 prices)	$24,325,000	$28,720,000	$14,450,000	$21,950,000	$27,410,000
Interest during construction	2,920,000	3,450,000	1,740,000	2,640,000	3,290,000
Total	27,245,000	32,170,000	16,190,000	24,590,000	30,700,000
Annual equivalent cost (6 percent, 40 years)	1,811,000	2,138,000	1,076,000	1,635,000	2,041,000
Annual operating costs					
Water purchase	$360,000	$1,980,000	$440,000	0	0
Power	735,900	1,105,400	104,500	$183,200	$348,900
Operation, maintenance, and replacements	148,800	169,600	250,000	63,900	110,600
Total	1,244,700	3,255,000	794,500	247,100	459,500
Total annual costs					
Total	$3,055,700	$5,393,000	$1,870,500	$1,882,100	$2,500,500
Per acre-foot of water supplied	85	150	234	53	70

SOURCE: U.S. Bureau of Reclamation, 1974.

Table 19a Summary of alternatives for supplying water to prototype oil shale development in Utah (Tracts U-a and U-b)

	Multi-purpose developments			
	Lower White River Project	Yellow Jacket Project (Joint with C-a and C-b—Pumping)	Yellow Jacket Project (Joint with C-a and C-b-Pumping and Gravity)	Yellow Jacket Project (Joint with C-a and C-b—Gravity)
Source of Water	White River and Watson Reservoir	White River and Ripple, Lost Park, and Powell Park Reservoirs	White River and Ripple, Lost Park, and Budford Reservoirs	White River and Ripple, Lost Park, and Budford Reservoirs
Annual firm water supply (ac.-ft.)				
Industrial	18,000	18,000	18,000	18,000
Municipal	18,000	18,000	18,000	18,000
Total	36,000	36,000	36,000	36,000
Quality of water diverted				
Total dissolved solids - (mg/1)				
Average	550	560	560	560
Range		250-800	250-800	250-800
Capital costs				
Construction cost (Jan. 1974 prices)	$12,930,000	$11,250,000	$11,987,000	$11,987,000
Interest during construction	1,560,000	1,350,000	1,440,000	1,440,000
Total	14,490,000	12,600,000	13,427,000	13,427,000
Annual equivalent cost (6 percent, 40 years)	963,000	838,000	893,000	893,000
Annual operating costs				
Water purchase	0	0	0	0
Power	$156,900	$225,000	$225,000	$225,000
Operation, maintenance, and replacements	52,600	65,000	68,000	68,000
Total	209,500	290,000	293,000	293,000
Total annual costs				
Total	$1,172,500	$1,128,000	$1,186,000	$1,186,000
Per acre-foot of water supplied	33	32	33	33

SOURCE: U.S. Bureau of Reclamation, 1974.

Environmental Impacts

Introduction

Assessing the environmental externalities of a potential oil shale industry necessarily involves a great deal of speculation because of uncertainties regarding choice of mineral process technologies, choice of development tracts, and future size of industrial output.

Oil shale lands in all three states support large and varied wildlife populations. Big game hunters from across the nation make seasonal excursions to Colorado's Piceance Creek Basin, which contains the State's most productive mule deer herd. Most areas embody a combination of natural and cultural conditions that promote good upland habitat, and a few areas contain good fisheries. Virtually all habitats are ecologically fragile. Mule deer, antelope, sage grouse, and certain other species would decline in numbers because of industrial activity and increased human occupance (U.S. Dept. Interior, 1973).

In-situ and modified in-situ recovery systems are generally regarded as more environmentally benign than mining and surface retorting methods. Whether this proves to be the case in all respects is not a certainty (Weaver, 1974). A pure in-situ system would likely require close spacing of injection and recovery wells, thereby removing the soil and vegetation cover from extensive areas. A large surface acreage would also be disturbed by the Occidental modified in-situ process since the tonnage of mined rock would equal about 62 percent of that extracted by conventional ex-situ methods. Both in-situ technologies could have profound effects on water resources, depending on the hydrogeology of the development tract. Some possible effects include dewatering of the target shales as a precondition to retorting, permanent alteration of subsurface porosity and permeability due to massive fracturing of the shale deposits, and contamination of either surface waters or groundwaters due to improper disposal of the large

quantities of retort water separated from the oil. Both in-situ technologies would also create underground spent shale dumps. Unless the site is isolated from circulating groundwaters, both vertically and horizontally, waters could move through the permeable spent shale, leaching soluble salts and the oily residue not recovered by wells or consumed by passage of the combustion front. The clearest environmental advantage of in-situ processing, including the Occidental modified technique, would be the lower potential for air pollution from surface facilities.

This section will describe some of the more serious environmental impacts that may be expected to occur under a commercial scale oil shale industry. In many cases there is only speculation because of uncertainties about how the industry will develop.

Energy Efficiency

Though not necessarily an environmental impact, the efficiency of energy use will be an important determinant of how or if a shale oil industry will develop. How much energy does it take to produce a specified amount of shale oil or shale fuels? (Schramm, 1975). Does expending energy to produce shale oil represent a wise use of energy? Answers to these questions have national energy policy implications. Several comprehensive energy input-output studies have been made. In one example, the total consumption net energy ratio was computed at 2.6: the external consumption net energy ratio was 8.8. Some of the organic matter in shale oil from a mine and processing plant complex is converted to fuels that supply most of the energy for the mining and processing operation. In the "total consumption" case, this fuel that is internally generated and consumed within the complex is included in the energy input to the system. In the "external consumption" case it is not. The overall thermal efficiency for pro-

ducing transportation fuels (gasoline and jet fuel, for example) was computed at 64 percent for a conservative case (28 gallons per ton of shale, etc.) and 78 percent for a more optimistic base (35 gallons per ton of shale, etc.) (Schramm, 1975). By way of comparison the overall thermal efficiency computed for producing similar liquid fuels from western coal was 62 percent and from eastern coal 65 percent; for a sour crude oil the efficiency was reported as 87 percent and for a sweet crude oil 92 percent.

Ground Water

A tremendous quantity of ground water is stored in aquifers throughout the Upper Colorado River Basin--considerably more than can be stored in existing and planned surface reservoirs (USDI, 1974b.). A large percentage of this water could be pumped for energy related purposes if problems related to reduced streamflow, water quality, and other environmental effects are acceptable to the user and the public. Specific quantities of groundwater that are available cannot be determined from presently available information.

For example, the Piceance Creek Basin has a well defined groundwater aquifer (Andrews, et al., 1975). The volume of water in storage in this basin has been estimated to be between 2.5 - 25.0 maf. The development plans for Federal lease tracts C-a and C-b called for near complete dependence upon groundwater. It is highly unlikely that a full 25 maf of ground water could ever be obtained from this area, even disregarding the rather significant environmental impacts that would be encountered if such extensive water mining were attempted. Probably no more than 50 percent of the groundwater supply could be mined and productively used. This is not an insignificant factor, however. One million acre feet of water could support a 100,000 barrel per day industry for more than 50 years.

The quality of water that can be mined is relatively low, being high in dissolved solids. USGS measurements of water salinity in the Colorado lease tracts are (Weeks et al., 1974):

Ca - above the mahogany zone ---- 1000 mg/l
below the mahogany zone ---- 3000 mg/l

Cb - above the mahogany zone ---- 1000 mg/l
below the mahogany zone ---- 5000 mg/l

Some measurements of groundwater salinity in the basin have been as high as 64,000 mg/l.

Water with dissolved solids exceeding 1000 mg/l is not highly suitable for use in an oil shale facility because of its corrosive potential (Andrews, et al., 1974). This view seems to be contradicted, however, by industry plans to rely solely on groundwater for development of the Colorado lease tracts. It is probable that treating of groundwater will be necessary prior to some uses and certainly prior to discharge into surface streams. These factors have been considered by Occidental Oil Company in its plans to develop tract C-b. Only time will tell whether groundwater in the Piceance Basin will be a blessing or a curse to oil shale development.

Water Quality

In general, a water quality problem exists because someone perceives or experiences damages, the individual or society is harmed or something valued by individuals or society is harmed (USU, 1975). These damages are experienced as economic loss, degradation of environmental quality, impairment of health, social dislocations, and the like. Society attempts to avoid these costs and hardships by imposing water quality standards or restrictions on water users that will maintain desired water quality.

With oil shale development, possible water pollution sources are: in-situ retorts, retorting plant discharges, drainage from spent shale and flood water run-off from storage ponds or shale disposal sites (Morse, et al., 1976). Some of these operations could affect groundwaters underlying the shale region, but there is little data available on these potential effects. For example, little

is known about the occurrence and movement of groundwater in oil shale beds after in-situ retorting or underground mining operations.

Land disturbances produced by mining and spent shale disposal can be expected to change the hydrogeology and water yield of development tracts. Mining of the sub-strata under tens to hundreds of square miles would create a labyrinth of new underground voids. Poorly sealed core holes, well bores, and mine shafts sunk through confining beds would destroy existing boundary conditions. A computer simulation model of the northern Piceance Creek Basin indicates that dewatering of active mines would drop the water table over large areas (Weeks and others, 1974). The initial effect would be to deplete the flow of fresh groundwaters to springs and creeks; later depletions would mostly involve saline groundwaters.

The already low volume of streamflow originating in the shale water sheds could be permanently diminished by groundwater overdrafts, by evaporation of drainage waters in abandoned open pits, and by evaporation of stormwaters impounded below spent shale dumps. Runoff from the more humid, pinyon-juniper watersheds might be increased if disturbed surfaces are reseeded with grass rather than woody vegetation and outflow is not depleted by the items described above. Spent shale dumps could also be managed as water-harvest areas if the dump surfaces were sealed with impervious materials rather than revegetated.

Changes in water yield caused by land disturbances may cause significant impacts on local water users and wildlife, but the potential for altering the water budget of the Colorado River is quite small. Natural runoff from the Piceance and Yellow Creek watersheds, for example, is only 15,680 acre-feet per year or less than 18 acre-feet per square mile (Wymore, 1974). Unit water yields from other shale lands are likewise quite low.

The net effect of oil shale development on water quality is difficult to

assess. On the one hand, land treatment and structural controls used in reclaiming disturbed surfaces could reduce sediment yields below those now existing. Overdrafts of salaquifers discharging base flow to streams would reduce salt loading of surface waters. For example, mine dewatering operations of federal lease tract C-b is expected to eliminate the saline inflow along at least 10 miles of Piceance Creek (Weeks, et al., 1974). Reallocation of water from irrigated agriculture to industrial or urban use might also improve salinity levels in the Colorado River system by reducing the salt load in irrigation return flows. Alternatively, new consumptive water use would increase downstream salinity by reducing the volume of dilution flows in the Colorado main stem. Potential salinity impacts are discussed more fully below.

Current plans for water pollution controls are expected to curb most pollutants that might get into surface waters. For an oil shale complex these could include pollutants from the retorting plant and from leaching of the spent shale. Retorting yields 2 to 5 gallons of water per ton of shale; this water is contaminated with dissolved gases (ammonia and chlorine), dissolved solids (carbonates, sulfates, mercury, selenium and arsenic), and organic compounds (phenols and carboxylic acids) (Morse, 1976). The water used to quench spent shale from the retort as well as water run-off from the spent shale disposal area will pick up silt, salts, and organic compounds. To prevent these pollutants from reaching natural water courses, oil shale complexes must provide for the retention or impoundment of retort and spent shale water. Alternatively, all of this water must be purified through some treatment process. In addition, upstream diversion dams will be needed to reduce the probability that the impoundment areas would be reached by flash floods.

It will also be important to avoid undue contributions toward increasing the salinity of the Colorado River (Schramm, 1975). Liquid waste containing the

organic contaminants must be contained. The salinity consideration is reinforced by a 1973 agreement between the United States and Mexico that would limit the salinity of the Colorado River flowing into Mexico to no more than 115 ppm ± 30 ppm above the average annual salinity of Colorado River water arriving at Imperial Dam.

Salinity in this case refers to the concentration of dissolved solids per liter of water (mg/l) (Morse, 1976). Salinity is already a serious pollution problem in the Colorado River Basin because of massive irrigation projects in the area with salty soils and because of natural mineral salt sources. There is the possibility that the oil shale industry could add significantly to this problem. However, concern over increasing salinity should be placed in perspective. Colorado River salinity levels are usually given in terms of salinity concentration at Imperial Dam on the California-Arizona border. It is estimated that the average salinity at this point on the river now measures 865 mg/l. It is shown in table 20 that a 50,000 barrel per day oil shale plant could increase the salinity concentration at Imperial Dam by .5 mg/l, and a 250,000 barrel per day plant would increase the concentration by 2.5 mg/l. Estimates vary regarding the impact of increased salinity on the lower Colorado Basin.

Colorado River Salinity

In recent years a number of studies have been conducted which have examined the factors causing salinity and its related problems in the river. One of the more recent and relevant studies was undertaken by the Utah Water Research Laboratory (USU, 1975). In this study, alternative scenarios for irrigated agriculture, energy development, and water export were considered for their impact on salinity in the river at Lee Ferry and Imperial Dam. The following is a brief summary of that analysis.

Scenarios for irrigated agriculture to affect downstream water quality are

Table 20-- Estimated salinity increases at Imperial Dam due to oil shale development

	Schedule 1				Schedule 2				Schedule 3			
Level of Development Year	1977	1980	1985	1990	1977	1980	1985	1990	1977	1980	1985	1990
Shale Oil Production (1,000 barrels per day)	0	50	250	750	0	100	1,000	1,600	0	400	1,350	2,500
Water Use (1,000 acre-feet per year)	0.9	8.7	42.9	118.0	3.3	17.4	159.0	253.0	9.6	69.6	211.0	388.0
Salt Diverted at 400 mg/l (1,000 tons per year)	0.5	4.7	23.3	64.2	1.8	9.5	86.5	137.6	5.2	37.9	114.8	211.1
Increase Salinity (Concentrations at Imperial Dam mg/l)												
Resulting from Diversion of Water	-	0.5	2.4	6.8	0.2	1.0	8.0 1/	9.3 2/	0.5	4.0	8.5 3/	10.6
Resulting from Domestic Return Flow	-	-	0.1	0.3	-	-	0.4	0.6	-	0.2	0.5	1.0
Total	-	0.5	2.5	7.1	0.2	1.0	8.4	9.9	0.5	4.2	9.0	11.6

1/ The effects on salinity concentrations at this level were limited by the availability of noncommitted surface supplies of 133,500 AF/yr. Approximately 69,700 tons of salt would be diverted with this water at 400 mg/l. If supplies are obtained from some other source, such as augmentation, the salinity effects would not be the same, and therefore, were not evaluated because the source of such additional water is unknown.
2/ Footnote 1/ applies but the values are 155,400 AF/yr and 81,100 tons of salt.
3/ Footnote 1/ applies but the values are 142,000 AF/yr and 74,300 tons of salt.

Source: Rattien and Eaton, 1976.

defined for the following four control levels and assumptions (codes for later reference are shown in parentheses):

(1) Existing practice--both the efficiency of irrigation delivery systems and non-farm irrigation efficiency are to continue as is (E_1).

(2) Improve on-farm efficiency through irrigation scheduling and system management without changing delivery efficiency (E_2).

(3) Improve delivery efficiency without changing on-farm efficiency. This option entails upgrading conveyance systems through such measures as canal lining and tighter control (E_3).

(4) Improve on-farm efficiency through both management and upgrading of application methods, where appropriate, and improve delivery efficiency (T).

In addition to these alternate levels of irrigation efficiency, this analysis also considered three levels of potential irrigation development. Table 21 shows the major irrigation development projects under consideration in the Colorado River Basin. A high, probable, and low development rate is shown for each project. These projects are expected to interact with energy development to affect both the quantity and quality of downstream flows in the Colorado River.

Table 22 shows the assumed quantities of water consumed by various energy production activities. Table 23 presents the alternate levels of energy development considered in the projections of water use and salinity impact. It will be noted that under the low level of energy development oil shale will be untouched. At the highest level of energy development 1,280,000 barrels per day will be produced accounting for about 20 percent of water devoted to energy. Thus, it becomes difficult to assess the exact impact of oil shale development on the overall competition for water use and its affect on water quality. Is oil shale to be considered the first or last water user in its competition with

Table 21. Increases in irrigated acreage from base year 1973, by project.

Project Name (WRSA)	Type of estimate	Increase in irrigated land 1977	1983	1985	1990
		(Acres. 1,000)			
Wyo. New Irrig. Lyman	H *	5	7	7	7
(1401)	P **	5	7	7	7
	L ***		7	7	7
Seedskadee	H		47	50	123
(1401)	P			3	7
	L				
Savery-Pothook	H				15
(1402)	P				
	L				
Jensen	H		7	7	7
(1403)	P		7	7	7
	L				7
Ute Indian (Cup)	H				
(1403)	P				
	L				
Small Irrig. (Utah)	H	9	13	13	20
(1403)	P	9	13	13	13
	L	3	13	13	13
Uintah (Cup)	H		4	13	20
(1403)	P		4	13	20
	L			7	13
Bonneville (Cup-Upalco)	H	4	7	7	7
(1403)	P		7	7	7
	L		7	7	7
Dallas Creek	H			7	7
(1404)	P			7	7
	L			3	7
Bostwick Park	H	5	5	5	5
(1406)	P			5	5
	L			5	5

Table 21 (Continued)

Project Name	Type of estimate	Increase in irrigated land 1977	1983	1985	1990
Fruitland Mesa	H		11	18	18
(1406)	P		4	12	18
	L			6	15
San Miguel	H				10
(1406)	P				
	L				
Animas-La Plata	H			26	65
(1407)	P				18
	L				12
Dolores	H		7	12	32
(1407)	P		2	6	18
	L				12
Hogback (N.M.)	H	2	4	4	4
(1407)	P	2	4	4	4
	L	1	4	4	4
Navajo	H	27	73	89	110
(1407)	P		48	83	105
	L		37	43	65
Ft. Mojave I.R.	H		7	8	14
(1502)	P		5	6	14
	L		5	6	14
Colorado River I.R.	H	20	42	48	50
(1506)	P	18	40	47	50
	L	17	39	46	50
Chemcheuvi I.R.	H		2	2	1
(1808)	P		1	1	1
	L		1	1	1
Misc. Lower Basin	H	4	23	3	
(various)	P	1	-19	-6	
	L	-7	-66	-16	

Source: Colorado River Salinity Forum, June, 1975 as taken from USU, 1975
* High, ** Probable, *** Low.

Table 22. Estimated water requirement for energy development in the Upper Colorado River Basin.

Type of Development	Water Use
Coal Gasification	10,000 AF/yr per 250 million SCF/day
Coal Fired Electrical Generator	15 AF/yr per megawatt
Shale Oil	9,000 AF/yr per 50,000 BPD plant
Tar Sands	1,500 AF/yr per 50,000 BPD plant
Coal Pipelines	20,000 acre-feet per 25 million tons of coal
Coal Mining	61 acre-feet per million tons of coal
Oil Refining	39 gal/bbl
Hydropower	**

** Could vary substantially depending on what fraction of evaporation losses are charged to power production.

Source: USU, 1975.

Table 23. Projected energy development increase by 1990 from base year 1974 for Colorado River Basin.

	Production Level Estimate			Annual Water Use 1000's of acre-ft		
	Low	Probable	High	Low	Probable	High
Coal Fired Elec. Gen. (MW)	19,770	26,350	37,080	243	303	525
Coal Gasification (10^6 cf/d)	250	1,785	2,877	0	63	142
Coal Slurry Pipeline (10^6 ton/yr)	6.2	29.2	32.2	2	20	23
Coal Mining (10^6 ton/yr)	113.9	165.8	260.1	4	10	16
Hydro (MW)	503	503	1,903	**	**	**
Nuclear (MW)	2,426	3,810	3,810	50	90	105
Oil Shale (thousand barrels per day	0	578	1,280	0	68	220
Tar Sands (thousand barrels per day	0	139	259	0	5	9
				299	599	1040

** Could vary substantially depending on what fraction of evaporation losses are charged to power production.

Source: USU, 1975.

agriculture, energy, and municipal developments? This consideration is important when trying to assess the economic or environmental impact of oil shale development in the Colorado River Basin.

Salinity changes resulting from water use activities in the Colorado River Basin are a result of two fundamental processes which occur in any hydrological system. These two processes are (1) salt loading which results from the dissolving of salts by water, and (2) concentrating effects which result from a natural or man-induced consumptive use of water leaving residual salts in a smaller volume of water. Both of these processes influence salinity levels within the Colorado River, and contribute to the increase in salinity levels as the river flows towards the ocean (USU, 1975). Using these basic principles a river basin simulation model was developed by the Utah State University research team to consider the salinity effects of alternative water use levels.

It is emphasized that the figures presented in this analysis are intended only to represent trends and to indicate, in general terms, control potentials for geographic areas, rather than to predict absolute values of actual change. For example, considerably more confidence could be placed in the magnitude and direction of change from a given base level than in the absolute value of a predicted new level.

Figure 17 provides a comparison of salinity effects at Imperial Dam from alternative irrigation control practices within the Colorado River Basin. Note that annual river flow is assumed to be 14 maf and all agricultural, energy and water export activities are held at their most probable levels.

The effects of changes in irrigation efficiency are shown with reference to a base curve (A) in which the irrigation efficiencies for each of the subareas of the basin are assumed to remain unchanged from those which currently exist. The largest impact occurs as a result of canal lining (E_2). An inverse

Set Designation & Flow	Utilization Level			Agriculture Efficiency Level	Salinity Control Projects
	Agric.	Energy	Export		
A 14M	M	M	M	-	No
B 14M	M	M	M	E_1	No
C 14M	M	M	M	E_2	No
D 14M	M	M	M	E_3	No
Tech. 14M	M	M	M	Technology	No

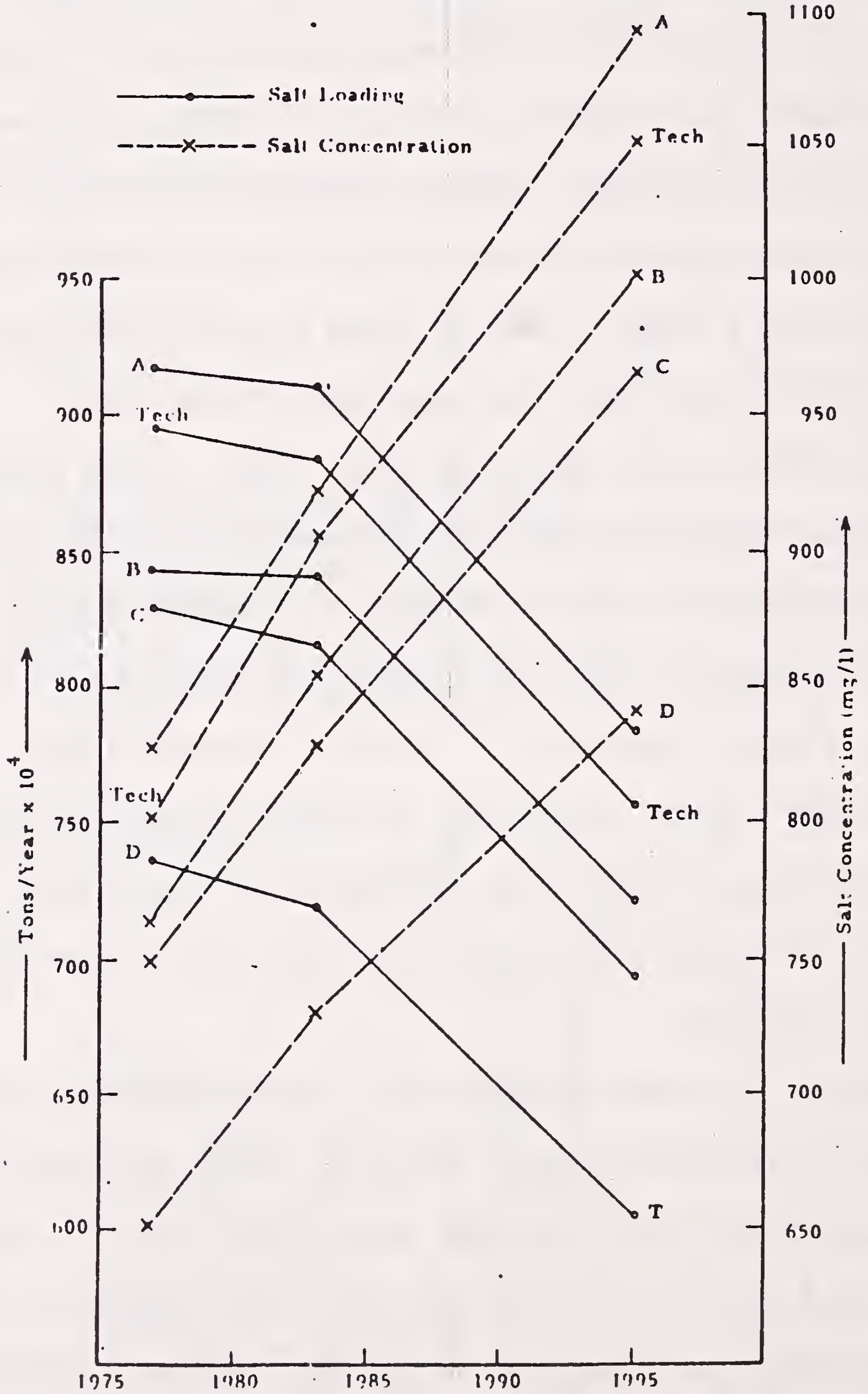


Figure 17. Predicted salinity effects at Imperial Dam of agricultural control practices within the Colorado River Basin.

Source: USU, 1975.

relationship exists between salinity and salt load also is indicated for Imperial Dam. This results because the rate of decrease in salt load is proportionally less rapid than the rate of decrease of water flow and thus the salt concentration is increased. This characteristic is typical of all curves for Imperial Dam, and results from the major diversions of water, and thus of salt, from the river in the lower basin. However, the curves for Lee Ferry, figure 18, indicate a general increase in both salt-loading and concentrations with the increasing development levels over time.

Figure 19 provides a look at the impact of high agricultural development. The difference between curves A and E represents the effect of moving to a high rate of irrigation development from the present or most likely rate of development. By 1995 salt concentrations at Imperial Dam would grow to about 1180 mg/l as compared to less than 1000 mg/l under current trends of irrigation development. Actual salt loads would not be much different but the dilution effect by removing water for irrigation results in the increased salt concentrations.

Again, movement to more efficient irrigation delivery systems, as indicated by curves F, would largely mitigate the adverse effects of water withdrawal. It should be noted that Robert Young, Professor of Economics, Colorado State University, has recently completed some research showing that the salinity contributions attributed to agriculture have been overstated (Leathers and Young, 1976). Thus, "cleaning up" agriculture by methods suggested here may have much less potential for improvement in water quality than shown in figure 19.

A comparison of increased energy development when flow of the river is assumed to be 14 million acre-feet and agricultural use is held at the median (most likely) level is indicated by lines A and J of figure 20. The obvious reason for the reductions in tonnage of salts is the reduced flow of the river. The flow at Lee Ferry, Arizona, might be projected to decline by an amount of

Set Designation & Flow	Utilization Level			Agriculture Efficiency Level	Salinity Control Projects
	Agric.	Energy	Export		
A 14M	M	M	M	-	No
B 14M	M	M	M	E_1	No
C 14M	M	M	M	E_2	No
D 14M	M	M	M	E_3	No
Tech. 14M	M	M	M	Technology	No

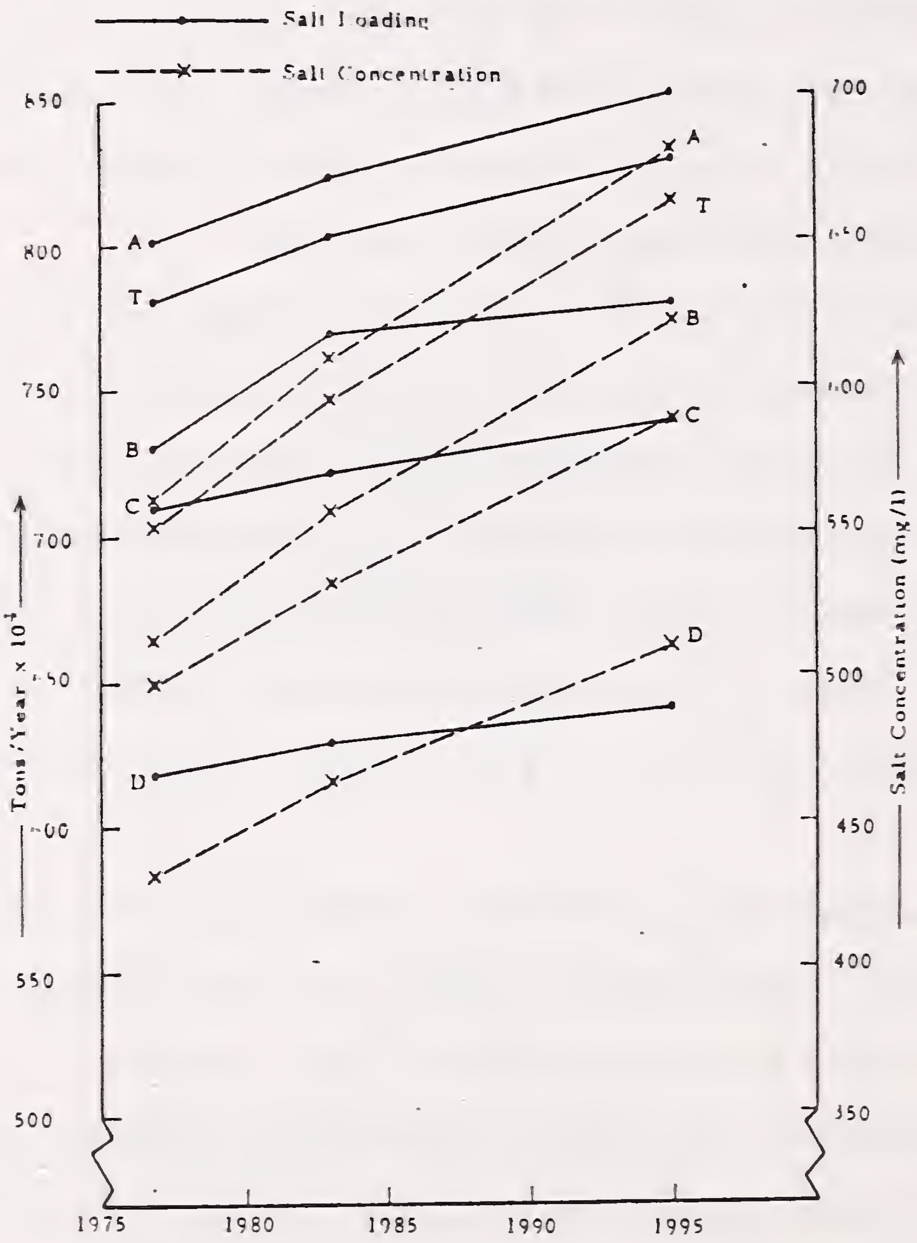


Figure 18. Predicted salinity effects at Lee Ferry of agricultural control practices within the Upper Colorado River Basin.

Source: USU, 1975.

Set Designation & Flow	Utilization Level			Agriculture Efficiency Level	Salinity Control Projects
	Agric.	Energy	Export		
A(base) 14M	M	M	M	-	No
E 14M	H	M	M	-	No
F 14M	H	M	M	E_3	No
M 14M	H	L	M	-	No

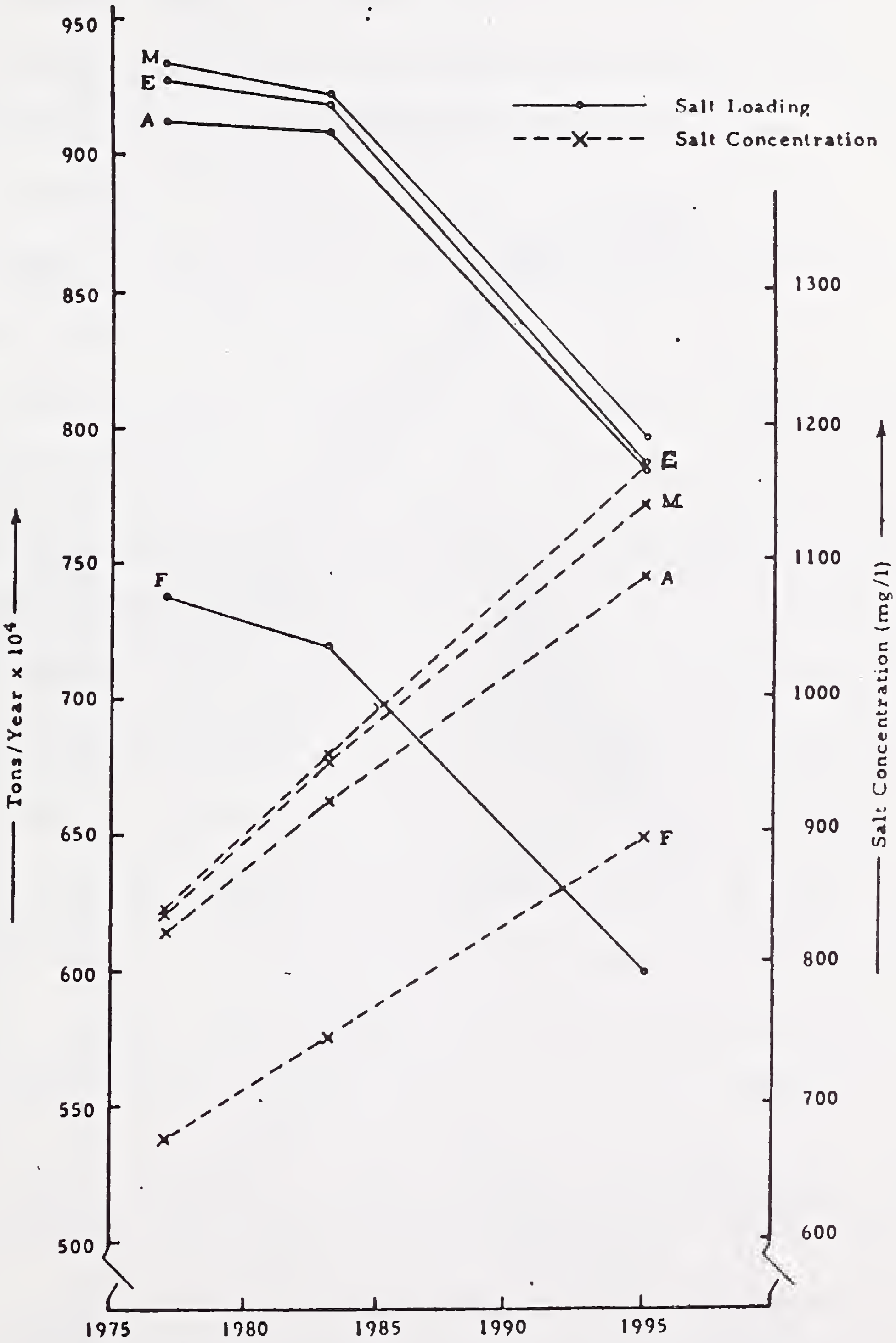


Figure 19. Predicted salinity effects at Imperial Dam, California, of alternate future uses and management options under conditions of high agricultural development within the Colorado River Basin.

Source: USU, 1975.

Set Designation & Flow	Utilization Level			Agriculture Efficiency Level	Salinity Control Projects
	Agric.	Energy	Export		
A (base) 14M	M	M	M	-	No
J 14M	M	H	M	-	No
N 14M	L	H	M	-	No
O 14M	L	H	M	-	Yes
P 14M	L	H	M	E_3	Yes
U 14M	L	M	M	-	No

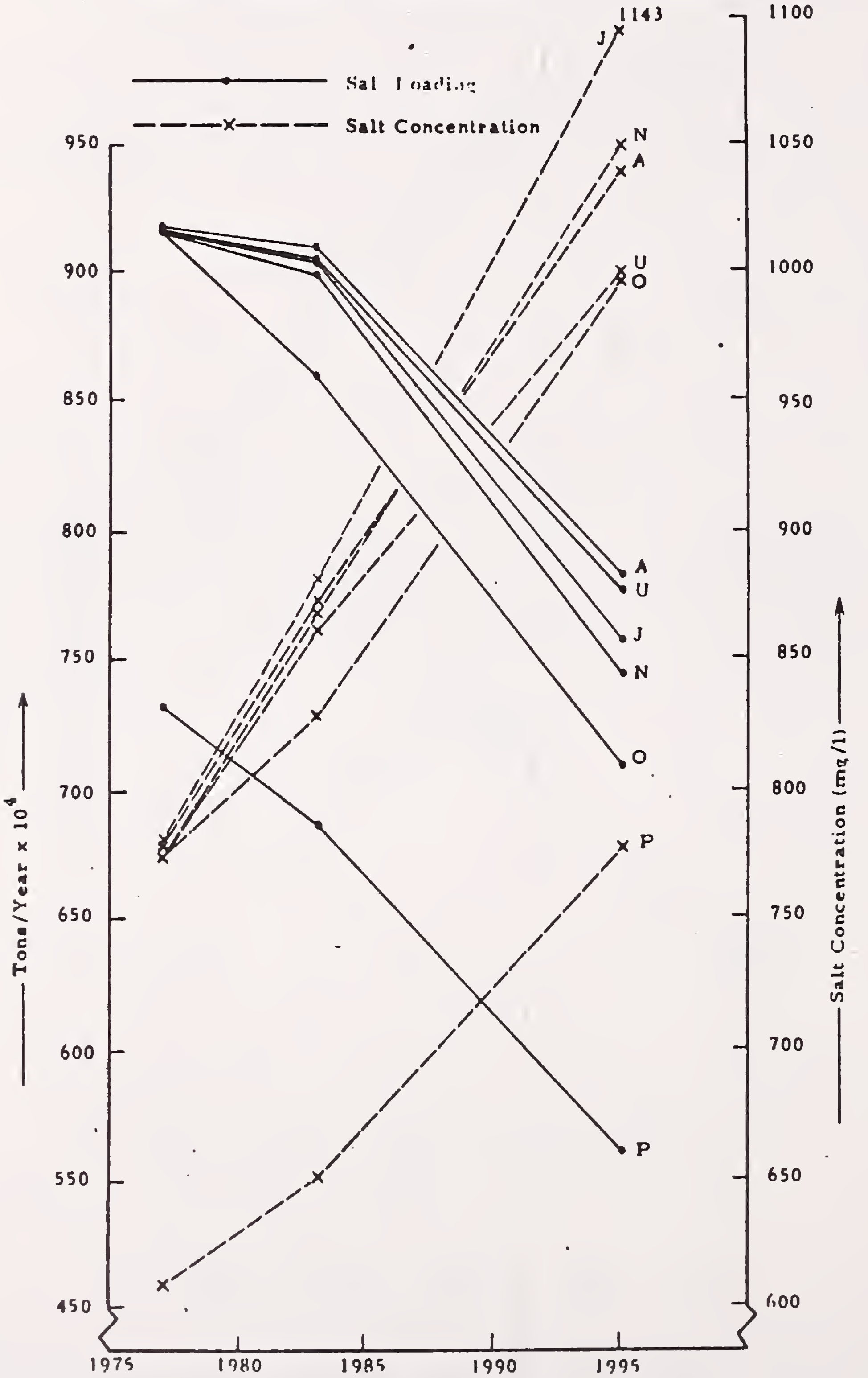


Figure 20. Predicted salinity effects at Imperial Dam of alternate future uses and management options under conditions of low agriculture and high energy development with the Colorado River Basin.

Source: USU, 1975.

1,730,000 acre-feet per year by 1990-2000 due to the increase from medium to high rate of energy development. While salt tonnage is reduced, salt concentrations in the river rise with the accelerated energy development. Under conditions of low agricultural development the same general trends occur as discussed above (compare lines U and N). Under both scenarios there is a decrease in salt load accompanying the energy increases over time. However, because of the associated higher rate of energy development the slope of curve N is steeper than that of curve U. The concentration changes for set N are relatively less than those for set J reflecting a larger amount of water flowing in the river for dilution for scenario N. In summary, the increased rate of energy development results in an export of water which reduces the salt load, but not sufficiently to offset the decline in dilution water, with the result that concentrations increase markedly.

The effectiveness of salinity control projects to mitigate high energy development effects on river concentrations is indicated by comparing curves N and O in figure 20. It is suggested that salinity control projects could reduce the salt load at the 1990-2000 development level by 52 mg/l. Because the loading changes are identical for the salinity control projects under all agricultural control options and rates of energy development, the physical possibilities for abating the salinity problem in this way look promising.

Model set P shows a low level of agricultural development with high levels of irrigation efficiency. Salt load in the river drops by nearly one-third and concentration by about one-fourth as compared to set O which has the same assumptions except for irrigation efficiency. It is apparent that the main effect is application of efficiency measures to irrigation. However, the low level of agricultural development relative to high energy development also contributes. In general it appears that the development of energy would reduce

the tonnage of salt in the river. However, it appears that concentrations would increase fairly rapidly due to consumptive use of water that would otherwise serve for dilution.

Figure 21 shows predicted salinity effects on Colorado River water at Imperial Dam as it is influenced by virgin flows and resource utilization. Curves A and X show the result of reducing virgin flows to 12 maf while holding water utilization at average levels. Salt concentration is increased from about 1100 mg/l to 1350 mg/l in 1995. Similarly, curve R illustrates the effect of virgin flows reaching 16 maf. In this case salt concentration reaches slightly over 900 mg/l by 1995.

It is obvious that energy development and resulting water consumption in the upper Colorado River Basin will have detrimental effects on downstream water quality. The exact role that oil shale development will play in this phenomenon is unpredictable at this point. Both the technology and likely level of development are unknowns today. It is evident that if oil shale development were to proceed very rapidly to, say, 1-2 million barrels per day by 1990 while holding other energy and agricultural water uses to modest levels, the marginal impact on downstream water quality could be considered rather modest. On the other hand, allowing other energy and agriculture to develop first significantly increases the potential marginal impact of ultimate oil shale development. To be sure, this kind of reasoning is not very productive but it does serve to illustrate some of the problems associated with predicting the adverse effects of oil shale development.

Cost Impacts

Knowing that some water quality problems will develop following any increase in upstream water utilization does allow a look at the next question. What are the economic costs of reduced water quality in the Colorado River? Agriculture,

Set Designation & Flow		Utilization Level			Agriculture Efficiency Level	Salinity Control Projects
		Agric.	Energy	Export		
A	14M	M	M	M	-	No
R	16M	M	M	M	-	No
S	16M	L	L	L	-	No
X	12M	M	M	M	-	No
Y	12M	H	H	H	-	No

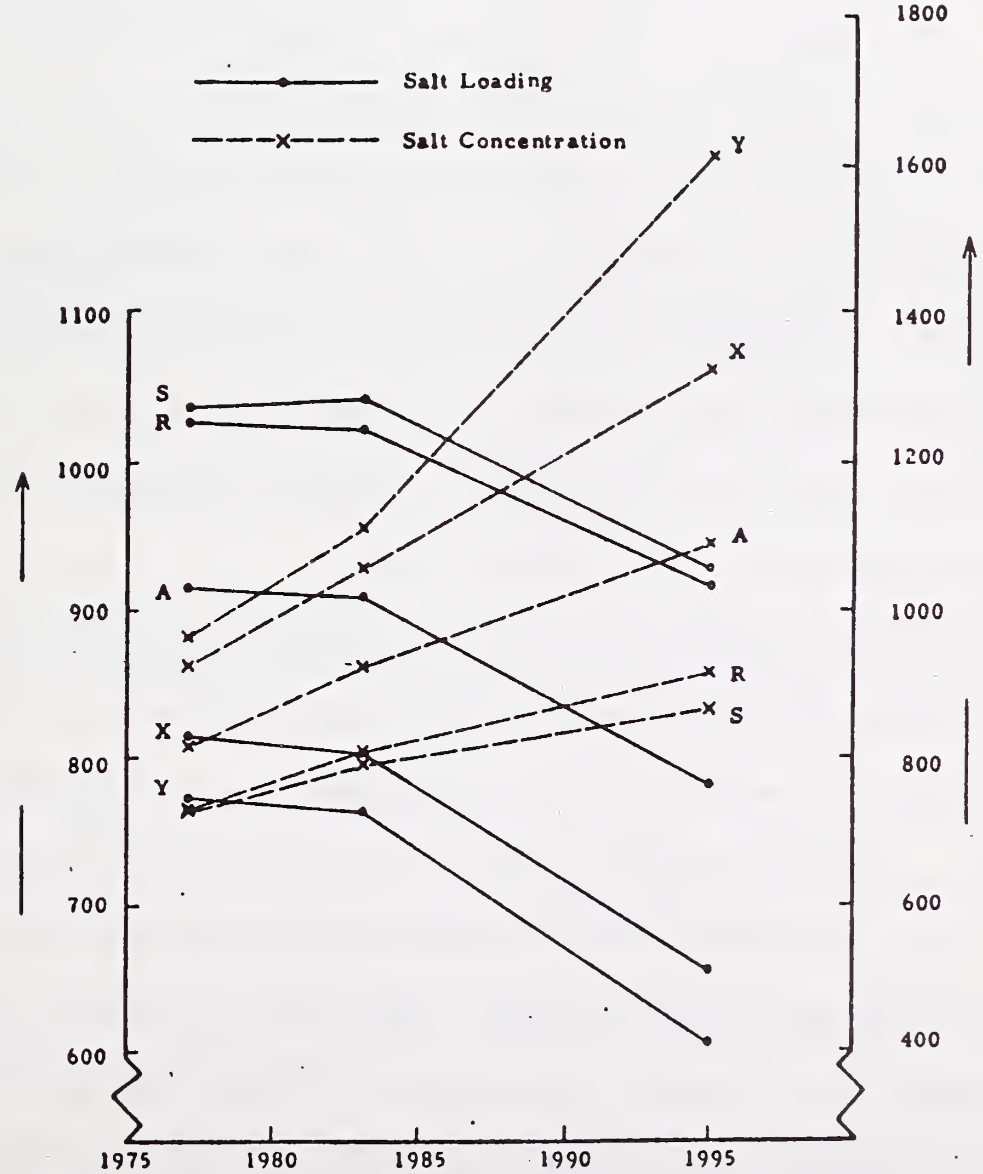


Figure 21. Predicted salinities at Imperial Dam as influenced by virgin flows and resource utilization rate.

Source: USU, 1975.

being the largest user of water, is impacted most by deteriorating water quality. The damages to agriculture are manifest in three ways. These are: a limitation on the types of crops that can be produced; a reduction of crop yields; and increased costs due to measures to avoid crop losses.

Damage estimates for irrigated agriculture have been made by the Bureau of Reclamation using the Sun (1972) model (USU, 1975). Sun estimated the reduction in net farm income to be \$16 per acre (1973 dollars) for nearly 470,000 acres in the Imperial Valley. This was an average penalty of \$.05 per mg/l per acre per year if salinity increased by 320 mg/l. The Bureau then estimated losses for other downstream project areas as being proportional, in terms of gross crop value, to the losses in the Imperial Valley. Based on this procedure and the utilization of an input-output model, the direct and indirect agricultural damages were calculated. Table 24 shows project area costs to range from \$9 per acre (\$0.028/mg/l/a) to \$65 per acre (\$0.203/mg/l/a). These costs are not insignificant when considering the move from currently less than 800 mg/l at Imperial Dam to over 1100 mg/l as may be effected by future energy and agricultural development. See figures 16-20.

The EPA (1971) projects that by 2010 salinity concentration at Imperial Dam will increase 464 mg/l from the 1960 level of 759 mg/l. Estimated damages for this change will amount to \$21,297,000 per year or \$45,900 mg/l/year in 1970 dollars. The EPA study is based on accepting loss of income through declines in crop yield while assuming that farmers would not likely take corrective action to combat rising salinity. They admit, however, that these estimates of damage losses may be lower than are currently being experienced.

The EPA estimates are far below the USBR-Sun figure of \$108,400/mg/l/year for the same 464 mg/l increment. This difference is significant and cannot be totally ignored. Young, et al. (1973) point out that the major difference must

Table 24. Summary of estimates of direct and indirect salinity impacts on agricultural users by area.

Area	Salinity effects per acre	Cost[1] mg/l per acre	Present modified acres	Total salinity effect cost per mg/l/year
Southern California				
Imperial County	$ 16	$ 0.050	526,000	$ 26,300
Coachella Valley[2]	59	0.148	40,000	7,500
MWD (San Diego)[3]	65	0.203	32,500	6,600
Palo Verde	16	0.050	103,800	5,200
Lower Main Stem				
Colorado River Indian Reservation	11	0.034	72,000	2,500
Remainder Yuma County	23	0.072	146,000	10,500
Gila Area				
Salt River Project (CAP area)[4]	9	0.028	50,700	1,400
Gila Project	21	0.066	105,000	6,900
TOTAL			1,076,800	$ 66,900
Indirect effects--0.62 x 66,900				41,500
TOTAL				$108,400

[1]Cost per mg/l per acre was based on Sun's 1972 study which predicted a crop response to change in salinity concentration of 320 mg/l.

$$\frac{\$16}{320 \text{ mg/l}} = \$0.05 \text{ mg/l/acre.}$$

[2]Twenty percent of the irrigation water comes from wells. The 40,800 acres represent 80 percent of present modified acres.

[3]Represents only the portion of agricultural lands which will not receive a blended water supply.

[4]Based on full service ground-water exchange acre equivalent of the CAP area that can be served with Colorado River water. (5.72 acre-feet per acre at canal side.)

Source: U.S. Dept. of the Interior/Bureau of Reclamation. Colorado River Water Quality Improvement Program: Status Report. January 1974, p. 32 as taken from USU, 1975.

lie in things like reduced double cropping and large (perhaps excessive) water application on high value crops (USU, 1975). Young, et al. also list a number of criticisms about the Sun approach to damage estimation but it is not clear whether costs are actually higher or lower than the USBR figures.

Boster and Martin (1975) have estimated the damages that would occur in Pinal County, Arizona, if the Central Arizona Project water has a salinity level of 1200 mg/l rather than 940 mg/l (USU, 1975). They concluded that if farmers are given opportunity to adjust their cropping pattern, the losses would amount to only $0.61 per acre or $0.44 per acre foot delivered to the county. The loss was less than $0.002/mg/l/acre foot of water delivered. They concluded that the salinity impacts of CAP water should not be of concern to farmers in the county.

The USU (1975) study offers one further comment on the appropriateness of the USBR-Sun approach. This derives from the fact that the per acre crop losses per mg/l for areas other than the Imperial Valley are the same proportion of the gross value of crops per acre as in the Imperial Valley. No consideration was given to physical differences between the compared areas. For example, the soils in the Imperial Valley are heavy in texture with problems in drainage. Hence, the salinity damages may be relatively higher in the Imperial Valley than they would likely be in other areas. The USU study adds that further work by the USBR has substantiated the estimates of salinity damage in the Imperial Valley but lower values have been confirmed for other areas of the Lower Colorado River Basin.

It is sufficient to conclude that additional energy or agricultural development in the Upper Basin states will have detrimental effects on downstream water quality. Further, such changes in water quality will have adverse impacts on agriculture. The exact amount of such imposed costs will vary among project

areas and will largely depend on physical characteristics of the region and the opportunities of agriculture to adjust as salinity increases.

There appears to be equal controversy regarding municipal and industrial impacts of increased salinity. The USU study cites USBR estimates of nearly \$120,000 per mg/l for municipal damages by year 2000 and compares them to EPA estimates of \$7,642 per mg/l, a vast difference. Industrial damage estimates are less variable ranging from \$1,148 (EPA) to \$1,500 (USBR) per mg/l per year. We have shown that as agricultural and energy development proceed in the Upper Basin States there will be impacts imposed on Lower Basin States due to changes in water quality. While the largest of these costs will probably be imposed on agriculture, mainly because agriculture is the largest user of water, other economic and social entities of the lower basin will be affected as well. There have been allusions to changes in agricultural water use in both upper and lower basin states that could be used to mitigate salinity problems in the Colorado River. Suffice it to say that agriculture could absorb the problem of salinity at a cost. The portion of this cost contributed by energy development could be made a transfer payment to agriculture through the Federal treasury system. It will probably be easier to mitigate negative impacts from energy development than from further agricultural development. At least energy uses will create revenues that can be used to help solve imposed problems whereas agriculture is less likely to be able to support the costs of its negative externalities.

An estimate of treatment costs of water produced from oil shale retorts is shown in table 25. These data taken from Fenix and Scisson (1976) indicate that the costs of processing or treating water from the 50,000 barrel per day plant could range from \$0.69 to \$1.44 per 1,000 gallons of water. The quantity of this water produced would be sufficient to supply the fresh water for a community

Table 25-- Costs of Treating Water Produced with a 50,000 barrel per day In Situ retort

	BEST CASE		WORST CASE	
	Units	Cost $/1000 gal.	Units	Cost $/1000 gal.
Retort Water	2.1 MGD		2.1 MGD	
Dissolved Solids	2,000 ppm		30,000 ppm	
Capital Cost: 10 year life				
Pretreatment		.30		.50
Reverse Osmosis Units		.09		.18
Total Capital		.39		.68
Operating Cost				
R.O. Membrane Replacement		.10		.20
Power @ 1.5¢/KW		.10		.40
Chemical Cost for pretreatment		.02		.04
Labor		.04		.04
Maintenance		.04		.08
		.69/1000 gal.		1.44/1000 gal.
Fresh Water costs				
Depreciation		.0038 per barrel of oil		.0076 per barrel of oil
Operation Cost				
Pretreatment		.0126* per barrel		.0210* per barrel
Reverse Osmosis Process		.0216 per barrel		.0319 per barrel
		.0290 per barrel		.0605 per barrel

(* Assumed cost)

Products:

Fresh Water	1.6 MGD (-200 ppm)
Reject Water	.5 MGD (8000 ppm)

Source: Fenix and Scisson, 1976

of 10,667 persons based on a use requirement of 150 gallons per day per person. Based upon these figures it is estimated that the cost of clean water from the in-situ retorting process could vary from $0.029 to $0.061 per barrel of shale oil produced without recovering any costs from community users.

Air Quality

Meeting air quality standards will be a principal constraint to mature industrial development. The remoteness of most development tracts should minimize materials damage and threats to human health, although in some cases inversion plumes could affect urban areas located miles downwind. Rural effects would include degradation of visibility and possible damage to vegetation and wildlife. Irrigated crops and meadows would be especially vulnerable because of their location on valley bottomlands affected by nocturnal inversions and temporary fumigation.

A recent Supreme Court decision interpreted the 1970 Clean Air Act as prohibiting significant air quality degradation in non-urbanized areas (Rattien and Eaton, 1976). Subsequently, the Environmental Protection Agency has effected rules to enforce this decision. The EPA ruling establishes three classes of air sheds. Class I refers to the unpolluted areas in which significant development is not permitted. This is enforced by very small permitted increments of air quality degradation resulting from development. Class II is for relatively unpolluted areas in which balanced development will be permitted. More substantial increments in pollutant concentrations are permitted under these circumstances. Class III air is primarily for urban areas, where the national and state ambient air standards will apply.

Table 26, taken from Rattien and Eaton (1976), summarizes the background information needed to assess the air degradation impact of a commercial shale oil industry. The size, location and number of oil shale processing plants in

Table 26-- Air Quality - Existing Status and Proposed Standards
(Expressed as ug/m^3)

Pollutant	Existing Quality in C-b tract Sept-Nov., 1974	Permitted incremental Air Pollution		Ambient Standards for Class III Areas	
		Class I	Class II	Federal	Colorado
Particulates					
3 Month Average (range)	(8.2-24.7)				
Annual Average		5	10	75	45
24 Hour Maximum	178	10	30	150	150
Sulfur Dioxide					
Annual Average		2	15	80	10
24 Hr. Maximim	136	5	100	365	55
3 Hr. Maximum	233	25	700	1,300	--
1 Hr. Maximum	269	--	--	--	300
3 Month Average (range)	(0.2-6.0)				
Nitrogen Oxides					
3 Month Average (range)	(6.7-7.0)				
Annual Average					
Carbon Monoxide					
8 Hour Maximum	14,098*			10,000	
1 Hour Maximum	14,563*			40,000	
Non-Methane Hydrocarbons					
3 Hr. Maximum	197			160	

* Reported measurement is questionable

Source: Rattien and Eaton, 1976

an area will have significant bearing on the ability of the industry to meet current or future air quality standards (Morse, 1976). Air quality degradation may come from emissions of fugitive dust (particulate matter) and from gaseous emissions including hydrogen sulfide, sulfur dioxide, nitrogen dioxide, carbon monoxide and various hydrocarbons. Fugitive dust sources are mining, crushing, retorting and spent shale disposal. The dust arising from these sources can be largely controlled with applications of water and surface agents. However the use of water to help control dust emissions would place an additional strain on the already scarce water resource.

One of the major problems related to air quality control in the oil shale area is the classification of the air sheds given to the region. Utah has zoned its state in a manner which will allow considerable energy development in the region of the shale oil deposits. The area of eastern-northeastern Utah has been given a standard equivalent to the Class II standards proposed by EPA. This would allow considerable energy development in the region of the oil shale deposits of Utah. Colorado, on the other hand, has declared the area of its oil shale deposits a Class I area with state standards slightly higher than those of the federal standard. In fact, these standards for Colorado are so high that the natural vegetation will violate the standards at some times. Also, dust or particulate matter in the region already exceed the standards of Class I air at certain times in the year. Under these circumstances it would be nearly impossible to develop a sizable industry in the Colorado portion of the oil shale region without violating the air quality standards. Rio Blanco County, which holds the bulk of the Piceance Creek basin oil shale deposits, has applied for a change of its air standards to Class II. Such a change would be more consistent than with the standards applied across the border in Utah.

For the oil shale industry, potential gaseous emission sources are retort-

ing, upgrading, and operation of gasoline or diesel powered equipment (Morse, 1976). These emissions can generally be controlled with conventional technology, such as stack scrubbers and precipitators. Unfortunately, while the shale industry can probably meet most federal and state particulate and gas emission standards, Colorado's current sulfur dioxide standards do pose a problem.

Colorado's sulfur dioxide standards, based on "best available control technology" are similar to federal sulfur dioxide standards based on "prevention of significant deterioration estimates," as shown in table 27. Colorado's mean

Table 27. Mean Annual SO_2 Standards* in Micrograms per Cubic Meter (ug/m^3).

General Description	Federal (EPA) Classification	Federal (EPA) Standard	State of Colorado Classification	State of Colorado Standard
Prioritive	Class I	2	Category 1	3
No Significant Deterioration	Class II	15	Category 2	15
Urban	Class III	80	Category 3	60

* A maximum permissible value, above a specified baseline concentration.

Source: (Federal) Telecon with John Dale, Environmental Protection Agency Denver Office, August 26; 1976.

(State of Colorado) Telecon with John Kinsey, Colorado Air Pollution Control Commission, August 26, 1976.

(Taken from Morse, 1976)

annual sulfur dioxide standard of 3 micrograms per cubic meter is much more restrictive than the federal standard of 15 micrograms per cubic meter. Rio Blanco County's request for reclassification as a category II area would make the state and federal standards consistent (Morse, 1976).

According to the Project Independence Oil Shale Task Force (1974), four 50,000 barrel per day oil shale plants in the Piceance would produce a mean

annual sulfur dioxide concentration of 9.9 micrograms per cubic meter, based on the removal of 99.5 percent of the sulfur dioxide from effluent gas. Thus, if Colorado's standards are not relaxed or more efficient controls are not developed, the Piceance Creek Basin might be limited to a single 50,000 barrel per day surface retorting plant.

Table 28 provides a summary of projected air quality in the Piceance Basin in 1990 under some alternative levels of oil production. It will be noted that Colorado's standards are violated in several categories with a 200,000 barrel per day capacity in the region. The Federal standards, however, would allow a much larger industry to develop. The current high quality air in Colorado results mainly from there being very little activity of any kind in the region today. The population base is very low, with only about 5 persons per square mile, and there is little or no heavy industry today. It would seem that both national and regional goals of economic and energy development could be better served by making Colorado's standards of air quality equivalent to those of the Federal standards.

At the time of this study, it is unknown as to whether Wyoming will follow the route of Utah or Colorado. Currently Wyoming's air quality standards are regulated by Federal standards.

It should be noted that the Occidental Oil Company is moving ahead with development plans for the C-b tract in the Piceance Creek Basin. This Company plans to develop a 57,000 barrel per day capacity plant using a modified in-situ process. At this time the Company is asking for no variances from the Colorado standards in order to proceed with development plans. Thus, it is expected that some industrial development can occur in the region even under current standards.

Table 28 -- Summary of Projected Air Quality in the Piceance Basin in 1990
(Concentrations in mg/m^3)

Pollutant	Projected Air Quality			Ambient Standards	
	200,000 Barrels a Day Capacity	500,000 Barrels a Day Capacity	1,800,000 Barrels a Day Capacity	Federal	Colorado
Sulfur Dioxide					
Annual Average	9.9	23	82	80	10
24 Hour Maximum	52	104	261	365	55
3 Hour Maximum	240	480	1,199	1,300	--
1 Hour Maximum	299	597	1,494	--	300
Particulate Matter					
Annual Average	18	24	37	75	45
24 Hour Maximum	16	31	77	150	150
Nitrogen Oxides					
Annual Average	7	16	47	100	--
Carbon Monoxide					
8 Hour Maximum	152	304	538	10,000	--
1 Hour Maximum	231	462	815	40,000	--
Non-Methane Hydrocarbons					
3 Hour Maximum	10	20	45	160	--

Source: Rattien and Eaton, 1976.

Land Disturbance

Growth of a mature industry using ex-situ technology would unavoidably involve massive reconstitution of the landscape because of the large tonnage of ore which must be extracted from the ground and the large volume of spent shale which must be disposed of after surface retorting operations. The tonnage of shale mined to support a 1 million barrel per day industry could reach 500 million tons per year (Morse, 1976), or 77 percent of the annual production rate of the entire U.S. coal mining industry. Spent shale output would accumulate at the rate of about 200,000 acre-feet per year. The material has little byproduct value (Culbertson, Nevans, and Hollingshead, 1970), and it appears that little or none of the wastes will be returned to the mine voids during early development of the industry. The normally higher economic costs of backfilling underground mines would be exacerbated by health and safety aspects of the hot, dusty solids and by threat of groundwater pollution due to high content of leachable salts in the wastes. Even if practical, backfilling could accommodate only 60 to 80 volume-percent of the residues because of the expansion attendant upon processing of the rock.

The prospects for successfully revegetating hundreds to thousands of acres of spent shale are problematical. Spent shale as it comes from the retort is highly saline, highly alkaline, and essentially devoid of plant available nitrogen and phosphorus (Harbert and Berg, 1974). These unfavorable properties could be ameliorated by artificially leaching and fertilizing the top layer of the waste dump prior to direct vegetative planting, or the raw medium could be covered with more viable soil material before reseeding begins. Neither strategy would eliminate the risk that accelerated erosion might later expose the untreated wastes. Natural revegetation of the untreated residues would be exceedingly slow and would likely culminate in a salt-desert community having little

value to wildlife, domestic livestock, or watershed protection. Recent plot studies also show that some residues can become resalinized within 1 year following treatment.

The severe disturbances (such as the surface disposal of large volumes of hot, dark colored spent shale into dry canyons) may result in drastic alterations of many micro-climate variables creating a number of revegetation problems (Wymore, 1974). For example, snow accumulation would not be expected on the freshly-laced spent shale piles because the surface temperature of the spent shale will remain above the melting point for several years.

Restoration of disturbed areas by natural revegetation would be extremely slow for the lower elevation zones of the Piceance Basin. Even on natural soils it takes approximately 17 years for natural shrub-grass regrowth to take place on small disturbed areas at the lower elevations, and approximately 8 years at the higher elevations. Therefore, natural revegetation is probably much too slow to be environmentally acceptable, except on the most favorable sites or relatively small disturbed areas. Spent shale disposal piles will be large, highly visible, harsh sites that would take a very long time for natural revegetation to occur.

Past studies indicate the necessity of modifying the plant environment, at least initially, so vegetation can be rapidly established (Wymore, 1974). This modification process includes leaching of the salts from the root zone of spent shale by sprinkler irrigation to tolerable levels for the selected species, covering the spent shale with tallus or top soil, mulching to reduce water evaporation and the potential lethal temperatures of solar radiation on dark spent shales, high initial fertilization. This is followed by annual nitrogen applications for up to three years, tightly fencing the revegetation to exclude domestic livestock and wildlife, seeding with adapted species selected for the specific site, and irrigation to supplement natural rainfall during one or two growing seasons to insure the establishment of successful vegetative cover.

The critical question will be whether an adequate plant cover for erosion control can be maintained under natural precipitation (Symore, 1974). Because the precipitation and vegetation will be in a delicate balance at the lower elevations and on southern exposures it may be necessary to provide standby irrigation systems for several years to maintain vegetation on critical areas during drought periods. Another unanswered question is how long the irrigation should continue. Experience on the research plots at Anvil Points show that a 60 percent ground cover could be established the first year. Since a 60 percent ground cover is more than the Anvil Points site can support under natural rainfall conditions it may actually be harmful to the vegetation to irrigate the second season because it can produce too dense a cover and discourage deep rooting.

It now seems commonly accepted that the revegetation of disturbed areas will only be attempted to the point of reestablishing a plant cover comparable to that which was in existence in the natural state. There is no point in attempting to establish highly productive grass covers under irrigation and fertilization that cannot be maintained in the long run under natural rainfall conditions. In much of the oil shale areas of Utah, Wyoming and Colorado overlaying the current vegetative cover is very sparse and unproductive in terms of agricultural uses. Thus, there is no reason to expect the lands once revegetated to be more or less productive than they were in the past. In any case, satisfactory revegetation can occur in the mined out areas. .

The success or failure of reclamation or revegetation on a large scale is difficult to predict at this time. Many experiments related to these activities are underway at this time. It is expected that the difficulties associated with this activity can be overcome through the application of known technologies. At this time reclamation activities are expected to add 4 to 7 percent to total production costs. It is not expected, however, that the long run productivity of

the region will be changed substantially by oil shale development.

Development Scenario and Regional Resource Use

Introduction

This section presents an anticipated development scenario for an oil shale industry. Its primary purpose is to form the basis for measuring regional impacts of such an industry and to allow a more specific focus on the agricultural impacts which could occur.

Predictions regarding oil shale development are bound to be very precarious, regardless of attempts to be conservative or general. Enthusiasm and plans for development have hit multiple peaks and valleys over the past several decades. The potential of the resource was recognized many years ago but each time that plans for its development began to emerge a new oil field was discovered, the costs of development rose prohibitively, or another obstacle was discovered. Thus, while there are some current plans to move ahead with oil shale production using a modified in-situ method of mining, the many failures of the past imposes a "wait and see" attitude among most of the industry representatives today.

Certainly the magnitude of the oil shale resource is reason enough to cause people to continue their efforts for development. With more than 1.8 trillion barrels of oil equivalents in the Green River Formation it is definitively a monumental resource holding great potential for future energy production. Of this total, it is estimated that up to 600 billion barrels of oil are recoverable with known technologies. In perspective, this would equal about 100 years of supply for the United States at present use rates. Of course, it will never be mined at a rate to equal current total petroleum demands because of resource and environmental limitations. Nevertheless, it could make significant contributions to future energy supplies if economic, environmental, and other resource supply problems can be overcome.

In order to proceed with an assessment of development needs and impacts it

is necessary to specify some assumptions regarding development potential. They are:

1. There will be a combination of mining methods used in developing the entire resource. Each part of the resource is most amenable to one or two types of mining, subject to some of the conditions of following assumptions.
2. Ultimately, those mining methods providing the highest level of resource recovery will become dominant. While less efficient methods such as underground mining may exist for a time, the ultimate value of the resource is too high for long run dependence on such methods. Thus, surface mining with various combinations of in-situ mining will ultimately prevail because they allow extraction of a greater portion of the in-place resource.
3. Limits on the ultimate size of the industry will be determined by a combination of resource limits (water and capital), environmental conditions, and economics. Water scarcity has long been considered to be a major limitation to a large scale industry. However, though large quantities of water will be required to develop the industry, capital limitations and environmental problems (air quality) will also be serious constraints to the industry. The ultimate size of the industry that can develop will be described by a combination of limiting factors that will prevail. Some of these include state and local policies that will develop to influence economic growth and the environment, technologies developed to minimize environmental impacts and water requirements, and the price of oil used to encourage or discourage incentives for production.
4. Development will begin in Colorado but eventually spread to Utah and

Wyoming as the industry grows. Early development is expected in Colorado because currently the greatest development effort is concentrated there. Also, the majority of the oil resource is in the Piceance Basin of Colorado and, hence, in the very long run production must be concentrated there. However, the oil shale resources in Utah and Wyoming could support sizable industries for many decades. Thus, the problems of water shortage and air quality in Colorado will force the industry to spread first into Utah and then into Wyoming. State policies toward these factors will ultimately influence the size and dispersion of the industry, making it difficult to be more precise at this time.

5. Commercial scale development will begin using underground room and pillar techniques and quickly include the modified in-situ mining process. However, oil shale formation characteristics, economics and environmental considerations will rapidly dictate the use of in-situ and open pit mining.

Table 29 presents an assumed mix of mining methods that will prevail for various sizes of the industry. While this technological mix is highly conjectural it is consistent with the assumptions described above. The purpose of this extrapolation is to provide a basis for estimating resource requirements and environmental impacts as the industry grows.

Levels of Resource Use

Water

Estimates of total water requirements for alternative levels of oil shale development are shown in table 30. These calculations are based upon the development scenario of table 29 and the water coefficients shown in table 5. These water use levels are based on fairly traditional estimates of oil shale

Table 29. Assumed mix of mining methods for alternative levels of shale oil production.

Process	Code	Size of industry (1,000 barrels per day) 250	500	1,000	2,000
Underground Mining (Room and pillar)	(UM)	50	50	50	50
Surface Mining (Open pit)	(SM)		100	300	500
Pure in-situ	(IS)			50	200
Modified in-situ	(MS)	100	100	150	250
Modified in-situ with surface retort	(MSR)	100	250	450	1,000

Table 30. Water requirements for development of mining, upgrading and ancillary facilities for shale oil production.a/

Mining Method b/	---1,000 barrels per day--- 250	500	1,000	2,000
	------------1,000 acre feet per year-----------------			
UM	6.75-10.50	6.75-10.50	6.75-10.50	6.75-10.50
SM		13.50-20.20	40.50-60.60	67.50-101.00
IS			2.95- 5.75	11.80-23.00
MS	6.10-11.50	6.10-11.50	9.15-17.25	15.25-28.75
MSR	7.10-11.60	17.75-29.00	31.95-52.20	71.00-116.00
Total	19.95-33.60	44.10-71.20	91.30-146.30	172.30-279.25
Average	26.78	57.65	118.80	225.78

a/ These figures are derived from tables 5 and 29. These data include water requirements for urban growth.

b/ See table 29 for code interpretation.

water needs. The range of water use for each level of production represents historical uncertainties regarding actual technologies which might be employed. There are choices between wet and dry cooling methods in upgrading oil and surface retorting. Water requirements for spent shale disposal can be highly influenced by the method of retorting employed. Indirect heat methods such as the Tosco II process will provide a potential for higher resource recovery but will use considerably more water for spent shale disposal than a direct heat method like the Paraho process. Environmental requirements for air quality and land reclamation will also influence the ultimate water needs. In the end, the cost and availability of water will largely dictate the amount that is used. Thus, there are many opportunities for substituting other resources or technologies for water, to explain the wide range of water requirements indicated in table 30.

The estimated water requirements for an industry size of 250,000 barrels per day are shown to range from 19,950 to 33,600 acre feet per year. The mid point or average of these extremes is 26,780 acre feet per year. The latter quantity is probably sufficiently accurate for further planning and discussions. A similar pattern holds for larger oil output levels. A 1,000,000 barrels per day industry will require an average 118,800 acre feet of water per year and an oil output of 2,000,000 barrels per day would require an average 225,780 acre feet of water per year. All of these water use coefficients include estimated needs for population increases.

How adequate are water supplies for meeting these projected needs? The answer to this question depends on several factors. A previous section has outlined the major arguments surrounding water supply problems in the oil shale region. Table 13 provides one set of water supply data that may be compared with the water demand data shown in table 29. It is shown that an estimated

451,000 acre feet of water are still potentially available for oil shale development in the three state area. This quantity of water might be adequate for considerably more than a 2,000,000 barrel per day industry which would require an estimated average 225,780 acre feet of water per year.

Unfortunately, the distribution of this water supply is weighted heavily toward Wyoming and Utah where ultimate oil shale development might be less commercially attractive than in Colorado where the major oil shale resources are located. Colorado shows a potential water supply of only 90,000 acre feet for oil shale uses. Hence, the distribution of oil shale production among the states might be a major factor in determining the ultimate size of the industry that could develop.

How well the oil shale industry might compete for water supplies in Colorado or elsewhere depends partly upon the attitude of the people and policy makers in the affected states. Table 14 shows that more than two-thirds of the current water depletions in the Upper Colorado River Basin is used by irrigated agriculture. Certainly agriculture is a marginal user of water in economic terms. The annual rental value of water in agriculture in the shale oil regions of Colorado is probably less than $20 per acre foot. Whereas, if water cost the oil shale industry $200 per acre foot it would add about $.07 to the cost of a barrel of oil. There are some institutional constraints being placed on the transfer of water from agriculture to industry in Colorado. For example, only the consumptive use fraction of the agricultural water right can be transferred and only during the historic periods of irrigation. Thus, industry would have to build upstream storage to make good use of water purchased from agriculture.

The effect of water limitations on development of an oil shale industry depends upon many currently unanswerable questions. Obviously, the distribution of the industry among the three states will largely affect the problems of water supply that are created. The actual limitations of water supply will depend

upon the means that are created for allocating or reallocating water supplies within states among competing uses. If the oil shale industry is allowed to complete with other uses, including agriculture, on economic terms it should fare very well and not be severely inhibited from development. Again, the priorities that individual states place on uses of water and the resulting opportunities or barriers for oil shale growth to compete will largely determine its ability to use water.

Some factors should be mentioned at this point which will mitigate or influence the long term effects of water supplies on oil shale development. First and perhaps most important, there is reason to question the accuracy of water use requirements that have been provided in the past and reflected in table 30. Generally these estimates of water use were developed with very limited experience in actual oil shale production. Consequently, "the worst possible case" was seemingly assumed in their calculation. The most recent estimates of water use for the modified in-situ process provided by Occidental Oil Co. (Ashland, Inc., 1977) are about equal to the lowest estimates in previously published data (for example, see USDI, 1974, p. 154). Both equal approximately 70 acre feet per year per 1,000 barrel per day oil production. It is now claimed that the Paraho surface retort process could operate with 20-25 percent as much water as previously estimated.

Moreover, initial developments in the northern portion of Colorado's Piceance Basin are expected to gain all necessary water requirements from mine dewatering and on-site groundwater pumping. For many years the water for mining activities in this area will be obtained in this manner. Of course, the ability to rely on groundwater will be affected by the size of the industry. Eventually, surface water will be required in some amount in all areas.

If technology adjustments can only reduce water demands to the low end of

the ranges illustrated in table 30, as would seem to be reasonable from more recent experiences, the inhibiting effect of water on growth would be greatly reduced. Part of the ability to accomplish this water saving will depend upon the method of mining, the choice of surface retort, environmental standards for air quality (dust control), and importantly, the availability of water.

Expanding on the latter, the availability and cost of water will largely determine the amount that is used. It has been shown that many opportunities for saving water do exist. However, most of these possibilities entail the substitution of capital for water or the potential sacrifice of oil recovery or an environmental standard. These trade-offs are apparent to the oil industry, so it is reasonable to expect initial development plans to call for all the water that could possibly be required. If, for example, the added investment cost of reducing water requirements for a 50,000 barrel per day plant from 7,500 acre feet per year to 5,000 acre feet per year is $100 million (the 57,000 bpd modified in-situ plant proposed by Occidental Oil Company has a 1977 estimated cost of $443 million), it would be rational to plan for the higher water using design. Under this assumption the water would have to exceed a cost of $4,000 per acre foot before it would pay to build the water efficient plant if capital were to receive 10 percent ROI. Thus, while many opportunities may exist for producing oil with less water, their adoption will be influenced by the physical availability of water plus many of the factors described above.

Land

Land use requirements for oil shale development will be subject to some of the same variability as described for water. The method of mining, amount of on-site oil upgrading, problems of spent shale disposal and the availability of land are some important factors that may influence the amount of land required or used. Table 31 provides estimates of land area requirements that may

be expected under alternative industry sizes. Because land area does not loom as a constraint on development of oil shale there will be less effort given to exposing its possible limits. It is shown here that approximately 6,550 acres would be occupied or disturbed at any one time by an oil industry producing 250,000 barrels per day. Up to 24,100 acres would be required for a 1,000,000 barrel per day industry.

Table 31. Land area requirements for development of mining, upgrading and ancillary facilities for shale oil production. a/

	1,000 barrels per day			
Mining Method b/	250	500	1,000	2,000
	Acres			
UM	1,750	1,750	1,750	1,750
SM		2,600	7,800	13,000
IS			750	3,000
MS	2,600	2,600	3,900	6,500
MSR	2,200	5,500	9,900	22,000
Total	6,550	12,450	24,100	46,250

a/ These figures are derived from tables 18 and 28.

b/ See table 28 for code interpretation.

In an area as vast as the Green River oil shale formation of Colorado, Utah and Wyoming these land requirements are rather small. Most of this land would be in areas of very low population density and economic activity. The major impacts of this land area disturbance will be environmental, though some cattle and sheep grazing will be affected. The agricultural impacts of land use will be assessed in another section. The environmental effects are difficult to

quantify but the land erosion potential and dust production from nearly 50,000 acres of land required for a 2,000,000 barrel per day industry are not insignificant. Much of this activity might be concentrated in the Piceance Basin where local effects could be substantial.

In any case, strict environmental standards plus requirements for land rehabilitation should minimize the long run detrimental effects of land disturbance. There is hardly another area of the U.S. that could experience land disturbance on this scale with less detrimental economic and social impact.

The estimates of land use shown in table 31 do not include land required for urban or population growth. This factor will be dealt with in the section discussing agricultural impacts.

Employment and Population

Employment and population growth induced by an oil shale industry become the basis for measuring major socio-economic impacts that may be experienced in the area of development. While these impacts will not be addressed in detail in this report, table 32 provides estimates of employment and population growth that may be expected from alternative sizes of an oil shale industry.

Primary and secondary annual employment induced by a 1,000,000 barrel per day industry is shown to reach 60,250 man years. Since peak employment during construction periods may be twice that of a long term production stage, it was assumed that 25 percent of the industry would be perpetually under construction at any one time in calculating these employment data. Further, it is assumed that a service multiplier of 0.5 exists for construction stage employment. That is, for every primary job provided by the industry during construction there will be 0.5 secondary jobs created. Similarly, the service employment multiplier for production periods is assumed to be 1.5.

Population growth shown in table 32 is based on assumptions of a population to employment multiplier of 1.8 for construction periods and 2.2 for production periods. Thus, it is shown that a 1,000,000 barrel per day industry could increase population by more than 125,000.

Impacts of this growth will be felt in increased demand for housing and social services. Land available for urban development will take on increased values, affecting the taxes of local residences. Impacts will be experienced by the local and regional economy, including the need for new public resources and expenditures, hyperurbanizations, new employment opportunities and changes in the structure of the economy and demography (Morse, 1976).

In the long run permanent population changes will require significant new investments of social capital to provide the necessary social services of education, sanitation, health protection, fire and police protection and transportation, to name a few. Table 33 is included to show possible costs and revenues that may be associated with population growth in a sparsely populated area like that under study. These data show that total state costs will likely exceed state revenues generated by such activity not including mineral royalties that may be collected. On a local basis, such as a county or municipality, the comparison would look even worse. It will be necessary to extract substantial royalties for minerals or energy extracted in order to adequately compensate local communities for problems and expenditures associated with growth of the oil shale industry.

Even moderate oil shale development could potentially generate serious socio-economic impact in the region. Extremely rapid growth that could be associated with a crash development program would be even more serious. The growth to a 2,000,000 barrel per day industry, increasing population by nearly one-quarter million, over a 25 year period should be considered as creating potentially seri-

Table 32--Average employment and population increases due to shale oil development. a/

Mining Method b/	250	500	1,000	2,000	250	500	1,000	2,000
	Employment - man years				Population - Number			
UM	3,050	3,050	3,050	3,050	6,250	6,250	6,250	6,250
SM		5,000	15,000	25,000		10,300	30,900	51,500
IS			1,700	6,800			3,500	14,000
MS	7,200	7,200	10,800	18,000	15,000	15,000	22,500	37,500
MSR	6,600	16,500	29,700	66,000	13,800	34,500	62,100	138,000
Total	16,850	31,750	60,250	118,850	35,050	66,050	125,250	247,250

a/ These figures taken from tables 19 and 28.

It is assumed that 25 percent of the industry would be under construction at any one time.

b/ See table 28 for code interpretation

Table 33-- Public Costs and Revenues in the Western Colorado Area over a 15 Year Period for Public Service Facilities.

Growth Condition	Capital Costs	Operating Costs	Revenues
Normal Growth (70,000 population increase)	$210 million	$208 million	$178 million
Moderate Oil Shale Development (131,000 population increase)	$393 million	$435 million	$372 million
Intensive Oil Shale Development (231,000 population increase)	$693 million	$611 million	$524 million

Costs and revenues are for local governments and school districts only. Figures do not include costs to service oil shale plants or the revenues from those plants.

Source: THK Associates, Inc., 1974, p. 52.

ous problems. Substantial state and federal planning and assistance would be required to ameliorate anticipated detrimental impacts.

Regional Distribution of Development

The distribution of shale oil development among Colorado, Utah and Wyoming will depend upon many factors. Some principles influencing the pattern of development such as oil reserves, water supplies and air quality considerations are discussed elsewhere in this report. A major factor only mentioned previously is the attitude of state policymakers toward oil shale development.

Colorado has taken a very cautious attitude toward this activity. Very high air quality standards have been imposed on the oil shale region of Colorado and, if not ultimately relaxed in some fashion, will prohibit more than a token industry. Colorado has taken a very protective attitude toward agricultural water rights making it difficult and relatively expensive for the oil shale industry to obtain water from this source. Though these examples of caution may not prevent a large scale oil shale industry in Colorado, they are not generally designed to encourage development. Colorado's severance taxes on energy extraction are rather low, however.

Utah, on the other hand, has deliberately imposed a lower air quality standard over its oil shale area to encourage development. Utah has a larger reserve of uncommitted water supplies some of which are being set aside for energy development. Utah is planning to build a dam on the White River with the expressed purpose of providing water for the oil shale industry. Utah is also trying to obtain ownership of about 170,000 acres of oil shale lands currently held by the federal government with the expressed view that this land could be used for development of an oil shale industry. Though the oil shale resources of Utah are far below those of Colorado, they are sufficient to support a very large oil shale industry for a long time.

This brief discussion only illustrates the great difficulty of predicting the regional distribution of a developing oil shale industry. Table 34 presents two possible distributions. The first is based on an assumption of existing state policies which would encourage development in Utah but not encourage development in Colorado. The second set of figures is taken from a published estimate of water use requirements for the oil shale industry (USDI, 1974). These two sets of figures probably form a reasonable set of bounds on the regional distribution of a developing oil shale industry. They may be useful in further assessing constraints to development or impacts of development.

Table 34-- Approximate distribution of oil shale industry among Colorado, Wyoming and Utah a/

	Size of Industry			
	1,000 barrels per day			
	250	500	1,000	2,000
	---------- Percent -------------			
Colorado	50- 80	50- 75	60- 72	60- 74
Utah	50- 20	50- 25	35- 22	34- 21
Wyoming			5- 6	6- 5
	100	100	100	100

a/ The first set of figures are based on assumed state policies which encourage development in Utah and discourage development in Colorado.

The second set of figures are estimated from distributions of water use for alternative industry sizes provided by USDI, 1974.

Agricultural Impacts of Oil Shale Development

Introduction

The shale areas of Colorado, Utah and Wyoming exist in sparsely populated arid regions of these states. Table 35 shows the general pattern of land ownership in the shale oil areas. The Federal government owns more than 70% of the land with private entities controlling most of the remainder. State owned land in the oil shale area is only about 5% of the total.

These statistics may be a bit misleading in that Federal lands take the centerposition in a geographical sense and, hence, cover an even larger percentage of the resource. Privately owned lands, particularly in Colorado, mainly lie on the fringes of the oil shale deposits. Moreover, many of the privately owned lands are now in the hands of large corporations whose interest is to eventually develop the oil shale resource.

This brief discussion of land ownership introduces the thought that there is actually very little traditional agriculture likely to be affected by oil shale development. This fact is verified in part by the amount of concern about agriculture shown by oil companies and the USDI in the detailed development plans for the four Federal lease tracts. In the several thousands of pages of these reports there is no discussion of the potential impacts on agriculture. This is not to say that agriculture in the region would not be seriously affected if development were concentrated solely on the private lands bordering the oil shale resource. However, that is an unlikely event because the richest, deepest and most extensive deposits of oil shale are under Federal ownership. This section focuses more closely on the potential agricultural impact that might be anticipated as an oil shale industry is developed.

Agriculture in the Oil Shale Area

The oil shale areas of Colorado, Utah, and Wyoming were arbitrarily divided

Table 35 --Land ownership status in the major oil shale areas

	Federal	Federal	State	Private
	%	------------Acres-------------		
Colorado a/	76	608,569	30,349	166,499
Utah b/	81	876,913	135,206	74,264
Wyoming c/	69	4,374,630	140,200	1,687,000
Total	72	5,860,112	305,755	1;927,763

a/ BLM Planning units: Piceance Basin and Yellow Creek

b/ BLM Planning units: Bonanza, Rainbow and Book Cliff

c/ Sweetwater County, Wyo.

Source: USDI, 1973

into two general categories for assessment of agricultural activity in the region. They are respectively, counties where oil shale development is "most probable" and a larger set of counties that could encompass "possible" development. These counties are listed below:

	Most probable development	Possible development
Colorado	Rio Blanco Garfield	Rio Blanco Garfield Moffat Mesa
Utah	Uintah	Uintah Carbon Duchesne Grand
Wyoming	Sweetwater	Sweetwater Sublette Lincoln Uinta Carbon

The 1974 Census of Agriculture was used to obtain primary agricultural statistics for counties in the three states. These data are shown in tables 36, 37, and 38 for Colorado, Utah, and Wyoming, respectively.

Land Use

In the counties of most probable development the extensiveness of the agriculture is demonstrated by the rather few and large farms existing therein. The average size farm in Colorado is 2,257 acres, 1,223 acres in Utah, and 9,678 in Wyoming. The type of agriculture is primarily livestock ranching with crop agriculture largely designed to produce forages and feed to support the livestock grazing activity. Corresponding cropland acreages per farm average 330, 172, and 342 for the same three states. Thus, the percent of total land in cropland per farm averages 15, 14 and 4, respectively, for counties of most probable development. The remainder of land in farms is generally range land of relatively low productivity. Moreover, considering only cropland on these farms, we note that

Table 36 -- Colorado Agricultural Statistics in the Oil Shale Area.[a/]

		Most Probable Development[b/]	Possible Development [c/]
All Farms	No.	385	1,371
Land in Farms	Acres	869,113	2,495,015
Average Farm Size	Acres	2,257	1,820
Total Cropland	Farms	355	1,285
	Acres	117,162	354,069
Average Acreage	Acres	330	276
Farm Production Expenses	$1,000	15,595	47,737
Value of Ag. Prod. Sold	$1,000	14,247	50,194
Average per Farm	Dollars	37,005	36,611
Crops	$1,000	2,829	17,593
Forest Products	$1,000	2	58
Livestock	$1,000	12,102	33,179
Cattle and Calves Inv.	No.	85,480	199,651
Hogs and Pigs Inv.	No.	735	10,423
Chickens	No.	4,253	15,091
Sheep and Lambs Inv.	No.	75,558	233,560
Cropland Harvested	Acres	71,114	191,624
Cropland Pasture	Acres	30,593	87,775
Irrigated Land	Acres	74,445	172,494

a/Source: 1974 Census of Agriculture. Based on farms with sales of over $2,500

b/Rio Blanco and Garfield Counties.

c/Rio Blanco, Garfield, Moffat, and Mesa Counties.

Table 37 -- Utah Agricultural Statistics in the Oil Shale Area.[a/]

		Most Probable Development[b/]	Possible Development
All Farms	No.	243	768
Land in Farms	Acres	297,099	1,192,616
Average Farm Size	Acres	1,223	1,553
Total Cropland	Farms	238	743
	Acres	41,023	158,751
Average Acreage	Acres	172	214
Farm Production Expenses	$1,000	4,826	14,953
Value of Ag. Prod. Sold	$1,000	5,001	15,251
Average per Farm	Dollars	20,580	19,858
Crops	$1,000	1,108	2,726
Forest products	$1,000	d/	3
Livestock	$1,00	3,876	12,418
Cattle & Calves Inv.	No.	34,009	103,052
Hogs & Pigs Inv.	No.	2,227	3,832
Chickens	No.	2,499	12,039
Sheep and Lambs Inv.	No.	22,260	65,959
Cropland Harvested	Acres	22,974	74,504
Cropland Pasture	Acres	14,242	70,476
Irrigated Land	Acres	33,783	120,590

a/Source: 1974 Census of Agriculture. Based on farms with sales of over $2,500.

b/Uintah County.

c/Uintah, Carbon, Duchesne, and Grand Counties.

d/Less than half a unit.

Table 38 -- Wyoming Agricultural Statistics in the Oil Shale Area.[a/]

		Most Probable Development[b/]	Possible Development
All Farms	No.	88	1,057
Land in Farms	Acres	851,629	5,282,039
Average Farm Size	Acres	9,678	4,997
Total Cropland	Farm	76	979
	Acres	25,962	540,678
Average Acreage	Acres	342	552
Farm Production Expenses	$1,000	3,946	46,910
Value of Ag. Prod. Sold	$1,000	3,968	46,211
Average per Farm	Dollars	45,091	43,719
Crops	$1,000	362	6,158
Forest Products	$1,000	0	25
Livestock	$1,000	3,604	40,020
Cattle and Calves Inv.	No.	17,639	311,123
Hogs and Pigs Inv.	No.	80	566
Chickens	No.	652	5,790
Sheep and Lambs Inv.	No.	94,626	352,933
Cropland Harvested	Acres	17,166	389,719
Cropland Pasture	Acres	8,367	141,757
Irrigated Land	Acres	22,090	476,346

a/Source: 1974 Census of Agriculture. Based on farms with sales of over $2,500.

b/Sweetwater County.

c/Sweetwater, Sublette, Lincoln, Uinta, and Carbon Counties.

cropland pasture accounts for 26 percent, 35 percent and 32 percent of total cropland on these same farms. In a general setting where more than 70 percent of total land is in public ownership and has no cropland, it becomes clear that agriculture in the region is not highly intensive.

Value of Production

In 1974 the total value of agricultural products sold from farms in the counties of most probable development equaled $14.2 million in Colorado, $5.0 million in Utah and $4.0 million in Wyoming. Of these totals 85 percent, 78 percent and 91 percent, respectively, are accounted for by livestock products. Tables 36, 37 and 38 indicate that both cattle and sheep numbers are relatively large in these counties.

The value of products sold in all counties where possible development could occur increases to $50.2 million in Colorado, $15.3 million in Utah and $46.2 million in Wyoming. This expansion of involved agriculture considerably broadens the potential that could be affected by oil shale development. While the ripples of secondary effects from large scale oil shale development would possibly be felt by some agriculture throughout this region there is no anticipation that a significant share of the total could be affected by any forseeable development possibilities.

The number of farms within the counties of most probable development is 385 in Colorado, 243 in Utah and 88 in Wyoming. These numbers are not large and do indicate the relatively low density of rural population in these counties. Average gross sales per farm in 1974 were correspondingly $37,005 in Colorado, $20,580 in Utah and $45,091 in Wyoming. Despite the relatively large acreages in these farms, income per farm remains rather low. These data are provided to indicate the magnitudes of agriculture that could be involved as oil shale is developed.

Irrigated Cropland

Since water is a critical resource in energy development activities it is also the most likely means for competing with agriculture beyond the actual boundaries of the oil shale mining activity, it is important to consider the level of irrigation that currently exists. Irrigated cropland in the counties of most probable development in 1974 totaled 74,445 in Colorado, 33,783 in Utah and 22,090 in Wyoming, see tables 36, 37 and 38.

Table 39 shows the distribution of irrigated cropland among crops in the oil shale region of Colorado (Rio Blanco and Garfield Counties). There is a

Table 39. Agricultural activity in Garfield and Rio Blanco Counties, Colorado

	Irrigated crops 1,000 acres	Distribution percent	Dryland crops 1,000 acres	Distribution percent
Wheat a/	0.70	0.87	9.80	11.41
Barley a/	0.90	1.12	2.40	2.79
Oats a/	0.90	1.12		
Alfalfa b/	35.27	44.08	2.23	2.60
Other hay and silage b/	17.69	22.12	2.92	3.40
Pasture b/	24.55	30.69	68.55	79.80
	80.01	100.00	85.90	100.00

a/ Source: 1974 Colorado Agricultural Statistics

b/ Source: 1969 Census of Agriculture

heavy weighting toward hay and pasture crops, which emphasizes the dominance of livestock agriculture in the region. Grain crops account for less than three percent of current irrigated land. The cropping pattern for irrigated land in

the oil shale regions of Utah and Wyoming is similar to that shown for Colorado.

The USDI (1973, b) has indicated that up to 20,000 acres of cropland could be absorbed by population increases induced by a million barrel per day industry. While this figure is only conjecture it does given some indication of the agricultural impact that could follow from this front. Compared to the total cropland in all three states in the "most probable" category of counties including 184,147 acres or the cropland in counties of "possible" development equaling 1,053,498 acres the figure of 20,000 acres is not overwhelming. More is said about this problem in a later section.

Agricultural Impacts

The previous discussion outlining the intensity and magnitude of agricultural activity in the oil shale region will form the basis for describing anticipated impacts of an oil shale industry. It has been shown that livestock ranching, both sheep and cattle, dominate the agricultural uses of land in the region. In general, there is a pattern of using rangeland for livestock support during the grazing season and then relying on irrigated forage production for the remainder of the year. Thus, there is a problem in assessing the impacts on rangeland or on irrigated land of not knowing how much the balance of agriculture is upset by also affecting the other one-half of the system.

Grazing

The lands likely to be lost to grazing are assumed to be the same as total disturbed lands from oil shale activity as shown in table 31. It is recognized that some disturbance will occur on croplands, particularly due to roads and pipelines. To offset this factor, however, there will be some impact of population increases on grazing lands due to the need for increased homesites. Since domestic land requirements are not included in the estimates of land use

shown in table 31, it is felt that the assumption of equating disturbed lands by mining activity with grazing losses is valid.

Table 40 presents measurements of estimated grazing losses due to shale oil development in Colorado, Wyoming, and Utah. The estimates of grazing productivity within this region are taken from data provided by the Bureau of Land Management. In general, this region is semi-arid with short growing seasons and consequently, of low productivity. The average grazing yield ranges from a requirement of 9 acres per animal unit month[1/] in Colorado to 14 acres per animal unit month in Utah.

Grazing losses stated initially in terms of animal unit months are shown in table 40. With a 1,000,000 barrel per day industry the impact would range from a loss of 1767 AUM in Colorado to 120 AUM in Wyoming. To put these figures into more meaningful terms it was further assumed that the grazing season on these lands was 4, 5, and 6 months in Colorado, Wyoming, and Utah, respectively. This assumption allowed the conversion of AUM data to equivalent numbers of cattle.

Table 40 shows the total number of cattle lost due to disturbance of grazing lands ranges from 145 with a 250,000 bpd industry to 1,054 with a 2,000,000 bpd industry. It must be noted that there are significant numbers of sheep grazed in this region, as shown in tables 26, 27, and 38. Much of the grazing loss would fall on sheep producers in these states though the impact data are stated in equivalent cattle numbers.

Table 41 takes the grazing loss data one step further. In this table the estimates of loss are compared to the number of cattle and sheep in the affected areas. Two such comparisons are made for each state. The first includes data only for those counties listed previously as having probable oil shale develop-

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1/ An animal unit month roughly measures the feed requirement of a full grown beef or dairy cow for one month or 5 sheep for one month.

Table 40 -- Estimated grazing losses from disturbed lands.

	Unit	Colorado	Utah	Wyoming	Total
Grazing productivity a/	Acres/AUM	9.0	14.0	12.0	
250,000 bpd					
Distribution b/	Percent	65	35	-	100
Land disturbed c/	Acres	4,258	2,292	-	6,550
Grazing loss g/	AUM	473	164	-	637
Number of cattle g/	Number	118 d/	27 e/		145
500,000 bpd					
Distribution b/	Percent	63	37	-	100
Land disturbed c/	Acres	7,844	4,606	-	12,450
Grazing loss g/	AUM	872	329	-	1,201
Number of cattle g/	Number	218 d/	55 e/	-	273
1,000,000 bpd					
Distribution b/	Percent	66	38	6	100
Land disturbed c/	Acres	15,906	6,748	1,446	24,100
Grazing loss g/	AUM	1,767	482	120	2,369
Number of cattle g/	Number	442 d/	80 e/	24 f/	546
2,000,000 bpd					
Distribution b/	Percent	67	28	5	100
Land disturbed c/	Acres	30,988	12,950	2,312	46,250
Grazing loss g/	AUM	3,443	925	193	4,561
Number of cattle g/	Number	861 d/	154 e/	39 f/	1,054

a/ Estimated from table IV-3

b/ Estimated as midpoint of ranges shown in table 25.

c/ Taken from table 22.

d/ Assumes a 4 month grazing season

e/ Assumes a 6 month grazing season, mostly sheep.

f/ Assumes a 5 month grazing season, mostly sheep.

g/ Stated in equivalent cattle numbers though sheep are also grazed on these lands.

Table 41 --Estimated portion of total livestock loss due to disturbed lands.

	Unit	Colorado	Utah	Wyoming	Total
Cattle equivalent-probable counties f/	number	100,592 a/	38,461 b/	36,564 c/	175,617
Cattle equivalent-possible counties f/	number	246,363 a/	116,243 b/	38,710 c/	744,316
250,000 bpd					
Grazing loss d/ e/	number	118	27	--	145
Share - probable counties	percent	0.12	0.07	--	0.08
Share - possible counties	percent	0.005	0.02	--	0.02
500,000 bpd					
Grazing loss d/ e/	number	218	55	--	273
Share - probable counties	percent	0.22	0.14	--	0.16
Share - possible counties	percent	0.01	0.05	--	0.04
1,000,000 bpd					
Grazing loss d/ e/	number	442	80	24	546
Share - probable counties	percent	0.44	0.21	0.07	0.31
Share - possible counties	percent	0.02	0.02	0.01	0.07
2,000,000 bpd					
Grazing loss d/ e/	number	861	154	39	1,054
Share - probable counties	percent	0.86	0.40	0.11	0.60
Share - possible counties	percent	0.04	0.13	0.01	0.14

a/ Taken from table 35
b/ Taken from table 36
c/ Taken from table 37
d/ Taken from table 39
e/ To calculate the percentages the grazing loss figure is increased by 50% to be comparable with the number of cattle and calves on farms.
f/ Cattle equivalent equals cattle and calves plus sheep, assuming five sheep equal one cow.

ment. The second includes all counties of each state having oil shale resources and listed as having possible oil shale development. Obviously, the impact on "possible" counties is far less than on "probable" counties because of the much broader base in the former category.

At 250,000 bpd the oil shale industry would potentially reduce cattle and sheep numbers by as much as 0.12 percent in Colorado in counties of probable development. The impact would be smaller in Utah and zero for Wyoming. If the industry reached 2,000,000 bpd, the grazing loss could reach 0.86 percent of cattle and sheep numbers in Colorado and 0.60 percent for the three state region.

These figures may be misleading as a result of the geographic base used for calculating their impact. While a county is the smallest governmental or geographic unit for which agricultural data are reported, the actual impacts may be concentrated on an even smaller area, particularly in the Piceance Basin where there is likely to be a concentration of oil shale activity which would focus grazing losses on a relatively few ranchers. Actually much of the private lands in these particular ranches are already owned by oil companies. The ranching activities thereon are continuing through leasing arrangements to previous owners of the land. Thus, while grazing losses will be real, there will be little change in resource ownership or compensation required as development occurs in this region.

In summary, the grazing impacts due to land disturbance from oil shale development are not large by any measure or standard. The annual variation in livestock production or the losses to coyotes would probably exceed the described losses from oil shale activity. Certainly there will be concentrations of effects that will result in greater impacts on some ranches and areas than on others. Compensation for these individuals should be a relatively minor problem, however.

Irrigated agriculture

Forming an accurate assessment of the potential impacts of oil shale development on irrigated land is more difficult than estimating grazing impacts. The impacts on irrigated agriculture are more subject to the whims of the industry, local governments, and the affected states.

A primary source of impact comes through the competition for water provided by the oil shale industry. This, in turn, is highly dependent on the distribution of the industry among states and the technology employed by the industry. A second source of impact is through the domestic land and water needs of increased populations. There is a tendency for population growth to occur adjacent to current towns or cities. Rangely, Meeker and Rifle in Colorado; Vernal, Utah; and Rock Springs, Wyoming are examples of areas likely to receive major population influxes. Frequently such urban growth will take both land and water from agriculture in the process. Some of these impacts can be influenced by patterns of industry development and state and local planning for urban growth.

Competition for water

This section will attempt to measure the potential impact on agriculture from the industrial demand for water. In this endeavor it will be assumed that no additional lands will be irrigated in the region to increase the intensity of competition between agriculture and industry. Further, it will be assumed that oil shale development is the only competitive user of water for agriculture. Certainly if all currently unused waters are given to coal production and then oil shale is developed the competition between agriculture and oil shale may be intensified.

The following discussion will disregard any interbasin distribution problems of water supply within states. Further, it will be assumed that all water

must be provided from surface flows in the Upper Colorado River Basin.

Table 42 presents estimated water requirements for a developed oil shale industry. The distribution of water needs among states is shown as a means of comparing the water needs with anticipated water supplies.

Reference to table 13 shows that, without reallocating any currently used water, oil shale development could receive the following amounts of water per year: Colorado, 154,000 af; Utah, 128,000 af; and Wyoming, 233,000 af. This allocation is based on an assumed average annual flow of 14.0 maf in the Colorado River and disregards other potential energy demands for water. These conditions might be termed the "optimistic case." Alternatively, using a more "pessimistic" view of Colorado River flows equaling 13.3 maf, the water available for oil shale in Colorado is reduced to zero. These data are summarized in table 43.

Table 43 provides a comparison of potential water supplies and demands for oil shale development. It is shown that neither Utah nor Wyoming should have difficulty meeting the water needs of oil shale development under any level of development or assumed flow in the Colorado River. For this reason it is possible that these states could receive a greater share of future development than is assumed here. In any case, meeting the water demands of oil shale development in these states should not detract water from agricultural uses. In fact, the state of Utah plans to build a dam on the White River to supply water to the oil shale industry. This dam would also allow development of about 13,000 acres of irrigated Ute Indian land near the confluence of the White and Green Rivers. Thus, oil shale development in Utah may have the effect of increasing agricultural output, at least in the short run.

Colorado presents a different set of circumstances, however. Table 43 shows Colorado to have adequate water for oil shale development up to an indus-

Table 42 -- Water requirements for oil shale production, by state.

	unit	Colorado	Utah	Wyoming	Total
250,000 bpd					
Distribution a/	percent	65	35	--	100
Water demand b/	1000 AF	17.41	9.37	--	26.78
500,000 bpd					
Distribution a/	percent	63	37	--	100
Water demand b/	1000 AF	36.32	21.43	--	57.65
1,000,000 bpd					
Distribution a/	percent	66	28	6	100
Water demand b/	1000 AF	78.41	33.26	7.13	118.80
2,000,000 bpd					
Distribution a/	percent	67	28	5	100
Water demand b/	1000 AF	151.27	63.22	11.29	225.78

a/ Taken from table 32.

b/ Taken from table 30 using the mid point of the range of water demands.

Table 43 -- Comparison of potential water supplies and oil shale water demands.

	Colorado	Utah	Wyoming	Total
	---- 1000 AF ----			
Water supplies for oil shale a/				
Optimistic Case b/	90 e/	128	233	451
Pessimistic Case c/	0	111	223	334
Water demand d/				
250,000 bpd	17	9	0	26
500,000 bpd	36	21	0	57
1,000,000 bpd	78	33	7	118
2,000,000 bpd	151	63	11	225

a/ Taken from tables 1 and 2 (water section)

b/ Based on assumed flows in the Colorado River of 14.0 million acre feet.

c/ Based on assumed flows in the Colorado River of 13.3 million acre feet.

d/ Taken from table 30.

e/ The amount that could be used for oil shale is 154,000 AF if 64,000 AF of over commitment to other uses is withdrawn and made available to oil shale.

try level of 500,000 bpd if an optimistic view of water supplies is taken. Beyond that level of production some water shortages appear.

If a lower level of water flow is assumed for the Colorado River, Colorado's excess water quickly diminishes to zero. Under this circumstance there is a possibility that an oil shale industry would begin to compete with agriculture for water in the very infant stages of development. Assuming these water demand and supply data are accurate and that all such water must be provided by surface flows in Colorado, it is possible to estimate how seriously oil shale would impact on agriculture.

Table 44 shows the current agricultural base in the major drainage basins of Colorado which could provide surface water for oil shale development. There are currently about 413,000 acres of irrigated land in these two basins consuming about 770,000 acre feet of water per year. Assume the worst possible case to prevail in which all of the water for a 2,000,000 bpd industry would come from agriculture or 151,000 acre feet. At the average rate of water depletion of 1.86 acre feet per acre of land this could reduce irrigated acreage by 81,000 acres. This would mean a potential reduction of 20 percent in the irrigated agriculture of these two basins in order to support oil shale development. Recall that domestic water needs are included in the total requirements shown in table 30.

How probable is this worst possible or pessimistic case? There are a number of mitigating factors to be considered that would certainly temper the potential detrimental impacts on agriculture.

First it is important to distinguish between water "requirement" and water "demand." The data used for representing oil shale water uses in this report have been used as if they fall into the "requirement" category. The term requirement implies a fixed need quite independent of the cost or availability of

Table 44 -- Agricultural water use in major oil shale regions of Colorado.

Crop	Unit	Colorado River Mainstem a/	Northwest Region b/	Total
Wheat	1,000 ac	1.6	1.2	2.8
Corn grain	1,000 ac	7.5		7.5
Corn silage	1,000 ac	5.2		5.2
Oats	1,000 ac	1.6	0.5	2.1
Barley	1,000 ac	3.5	1.0	4.5
Orchard	1,000 ac	4.3		4.3
Vegetable	1,000 ac	0.7		0.7
Alfalfa hay	1,000 ac	62.7	22.3	85.0
Other hay	1,000 ac	57.1	106.8	163.9
Dry beans	1,000 ac	0.3		0.3
Crop pasture	1,000 ac	39.1	32.5	71.6
Other pasture	1,000 ac	36.2	28.8	65.0
Total acres		219.8	193.1	412.9
Total water depletion	1,000 ac	444.8	324.6	769.4
Average water depletion per ac	AF	2.02	1.68	1.86

Source: Whittlesey, 1977.

a/ Includes Eagle, Garfield, Grand, Mesa, Pitkin and Summit Counties.

b/ Includes Jackson, Moffat, Rio Blanco and Routt Counties.

water. Demand, on the other hand, implies a functional response in quantity used to the cost or price of water. It would, therefore, be much more realistic to describe the water "demand" of an oil shale industry rather than its water "requirements." There are definite technological options in mining, retorting, and upgrading oil shale that could adjust the water use in the industry over a wide range. Thus, the water coefficients used in this report and elsewhere are generally considered to be a "worst case" condition. If water is available and cheap the oil shale industry will probably use it in significant quantities. If water supplies become restrictive the industry can probably develop using much less water than previously anticipated.

It should also be recalled that some of the conditional claims on Colorado water rights are held by industries whose intent is to use this water for oil shale development. See table 16 for some examples of this. Also, included in Colorado's water commitments are as much as 90,000 acre feet of water in Green Mountain Reservoir and Reudi Reservoir which could be made available to the oil shale industry. Further, we cannot ignore the potential contribution of groundwater to the oil shale industry. It is believed that several million acre feet of groundwater may eventually be available in the Piceance Basin.

An underlying assumption of this analysis is that no intrabasin water distributional problems will occur. It is probably true that some of the "available" water within states is in river subbasins away from the oil shale area, per se. Hence, this analysis may overstate the water supplies available for oil shale development and consequently understate the local or regional impacts on agriculture.

It should be possible to develop an oil shale industry exceeding 2,000,000 bpd and have only minimal impacts on agriculture through competition for water. Since much of the water used by agriculture in this region is rather inefficiently

applied and utilized, there may be opportunities for "saving" enough water in agriculture to offset the needs of an oil shale industry. Table 45 illustrates the opportunities for achieving this reduction in water use in agriculture. Of

Table 45. Water depletion by agriculture under alternative conditions of efficiency - Colorado.

	Present Condition	Improved Management	Lined Canals	New Technology a/
	1,000 acre feet			
Colorado River Mainstem	445	428	415	366
Northwest Region	325	311	315	279
Total	770	739	730	645
Reduction from present	-	31	40	125

a/ The new technology condition includes lined canals, improved management, and new on-farm irrigation systems.

Source: Whittlesey, 1977.

course, the costs could be very high for achieving improved water use efficiency in agriculture. Also, there would have to be changes in the legal and institutional factors surrounding water rights in order to compensate agriculture for such water saving measures and to divert the saved water to energy development.

Competition for land

Aside from the use of agricultural water for industrial and urban growth, there is also the competition for land imposed on irrigated agriculture by urban growth. It is a fact that the level, accessible irrigated lands in the valleys of the oil shale region are also the most amenable to subdivision for urban development. Water is available. Roads, streets, and other necessary utilities are easily constructed. The question is how much currently irrigated land is likely to be used for urban development.

In answering this question it will be assumed that all potential urban growth due to oil shale development will occur on irrigated land. While this, in itself, may overstate the use of irrigated land for dwellings, there will undoubtedly be considerable growth in ancillary industries and businesses to require land which this analysis will not directly measure. These two factors should be somewhat offsetting.

It is difficult to say with certainty how much land will be required to serve increased population needs in a given area. Partially, the answer depends upon the reason for the population increase; stability or mobility of the population influx, income levels; type of planning given to development and growth; and availability of land and water. In this regard, some necessary assumptions must be made.

It is assumed that populations associated with construction employment will be relatively transitory. They will most likely congregate in rather densely populated mobile home tracts. It is assumed that the lead time for significant population increases will be sufficient to allow the planners for urban growth to discipline the patterns of growth. Due to a recognized importance of preserving land and water in the oil shale region, the more permanent urban growth will be in the form of traditional city lots. The land area per dwelling will be small.

Table 46 shows estimates of land use requirements for urban growth under alternative industry sizes. Two sets of land use coefficients are shown. The first is based upon an assumption of using 0.10 acre per capita population growth. It is believed that this rate of land use is most likely to occur. It results in the absorption of over 12,000 acres of land for a 1,000,000 bpd industry.

An alternative level of land use, 0.16 acre per capita, is shown also.

Table 46 -- Land use for urban growth

	Unit	Size of Industry -----1,000 bpd----- 250	500	1,000	2,000
Population Increase a/	number	35,050	66,050	125,250	247,250
Land use b/					
.10 acres/capita	acres	3,505	6,605	12,525	27,725
.16 acres/capita	acres	5,608	10,568	20,040	39,560

a/ Taken from table 31.

b/ Source: Whittlesey, 1977.

This rate of land use is representative of some urban growth areas in Eastern Colorado. However, it is believed that concern within the state and region for preservation of agricultural land and water will result in a lower level of land use.

These estimates include only the land needed to actually accommodate the population increase. It does not account for unused land that may be idle or underutilized in urban areas. Also, it does not include land that may be prematurely and speculatively subdivided for urban development. The permissive attitude of some county governments toward zoning and subdivision location often results in unneeded land being subdivided and set aside for urban growth.

The reader should also be reminded of changes in agriculture already occurring in the study region. Commercial agriculture is virtually non-existent or diminishing rapidly in portions of the area due to increases in recreational pressures. These developments have priced land out of reach for most agricultural uses in recent years with the result that agriculture is being reduced in importance. Thus, the imposition of an oil shale industry can only accelerate a process already underway in many cases. In fact, the agricultural impacts of an oil shale industry are likely to be smaller than those already felt from recreational pressures. We must be careful not to blame energy development for the demise of an industry that is dying or already dead.

Ammonia Production

A necessary by-product of shale oil upgrading is liquid ammonia, a highly prized fertilizer input for commercial agriculture. Shale oil is relatively high in nitrogen content which must be removed in order to meet most environmental standards for petroleum use. Though the amount of ammonia recovered will partially depend upon the retorting process used to recover the oil, the example of the development plans for Utah tracts Ua and Ub will serve to illustrate the

potential contribution of oil shale to the fertilizer market. In this case, a 100,000 bpd plant will produce 412 tons of liquid ammonia (NH_3) per day. At this rate a 1,000,000 bpd would produce 4,120 tons of liquid ammonia per day. In a world facing significant shortages of natural gas, the common feedstock for liquid ammonia, oil shale may be able to make an important contribution to fertilizer production. Though the benefits of this activity would largely accrue to agriculture outside the oil shale region, nevertheless, it would be a positive impact on agriculture.

Conclusions

The agricultural impacts of oil shale development are not entirely predictable. It is not expected that impacts through competition for land use will be very significant. The magnitude of disturbed land from oil shale development and irrigated land used for urban growth are both relatively minor in comparison to the agricultural base of the region.

The competition for water could potentially have much greater impacts on agriculture, though it is difficult to be very precise in the matter. Much depends upon the ultimate size of the industry, its location or distribution among states, the actual availability or supply of water (particularly in Colorado), and the technologies or methods used to extract oil from the shale. As much as 20 percent of current irrigated agriculture could be lost in this manner in Colorado though such effects should be negligible in Utah and Wyoming. Good planning by state and local governments and industry representatives could significantly mitigate such potential impacts on agriculture without unduly discouraging development of the oil shale industry.

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